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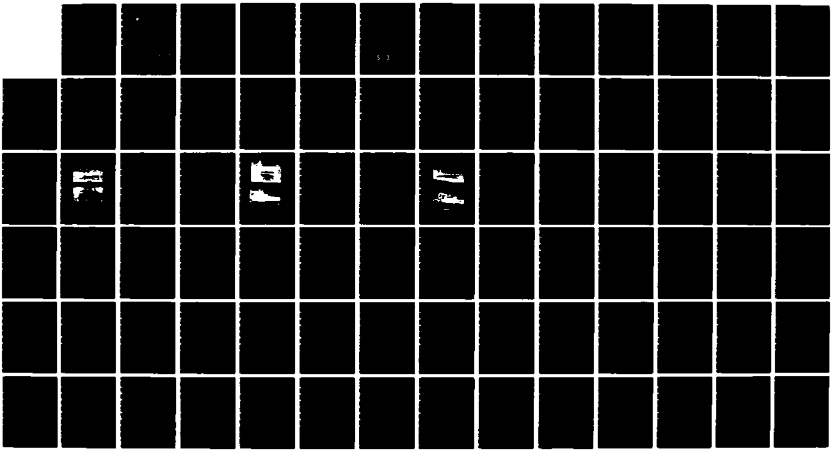

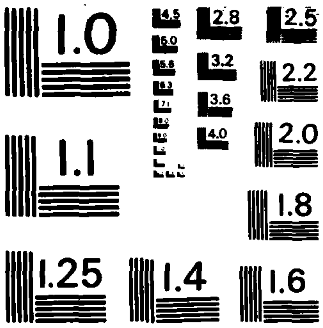

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NAVAL CIVIL ENGINEERING LABORATORY
Port Hueneme, California

Sponsored by
NAVAL FACILITIES ENGINEERING COMMAND

AD A139861

INITIAL FEASIBILITY REPORT ON DECENTRALIZED SMALL COGENERATION FOR NAVY SHORE BASES

February 1984

An Investigation Conducted by
OAK RIDGE NATIONAL LABORATORY
Oak Ridge, TN 97830

N68305-83-WR-30083

84 04 04 002

METRIC CONVERSION FACTORS

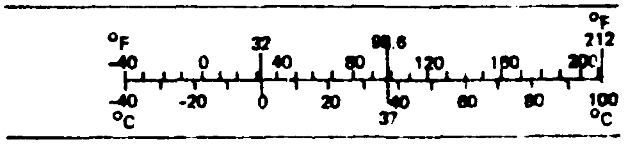
Approximate Conversions to Metric Measures

Symbol	When You Know	Multiply by	To Find	Symbol
		LENGTH		
in	inches	*2.5	centimeters	cm
ft	feet	30	centimeters	cm
yd	yards	0.9	meters	m
mi	miles	1.6	kilometers	km
		AREA		
in^2	square inches	6.5	square centimeters	cm^2
ft^2	square feet	0.09	square meters	m^2
yd^2	square yards	0.8	square meters	m^2
mi^2	square miles	2.6	square kilometers	km^2
	acres	0.4	hectares	ha
		MASS (weight)		
oz	ounces	28	grams	g
lb	pounds	0.45	kilograms	kg
	short tons (2,000 lb)	0.9	tonnes	t
		VOLUME		
tsp	teaspoons	5	milliliters	ml
Tbsp	tablespoons	15	milliliters	ml
fl oz	fluid ounces	30	milliliters	ml
c	cups	0.24	liters	l
pt	pints	0.47	liters	l
qt	quarts	0.95	liters	l
gal	gallons	3.8	liters	l
ft^3	cubic feet	0.03	cubic meters	m^3
yd^3	cubic yards	0.76	cubic meters	m^3
		TEMPERATURE (exact)		
°F	Fahrenheit temperature	5/9 (after subtracting 32)	Celsius temperature	°C

*1 in = 2.54 (exactly). For other exact conversions and more detailed tables, see NBS Misc. Publ. 286, Units of Weights and Measures, Price $2.25, SD Catalog No. C13.10:286.

Approximate Conversions from Metric Measures

Symbol	When You Know	Multiply by	To Find	Symbol
		LENGTH		
mm	millimeters	0.04	inches	in
cm	centimeters	0.4	inches	in
m	meters	3.3	feet	ft
m	meters	1.1	yards	yd
km	kilometers	0.6	miles	mi
		AREA		
cm^2	square centimeters	0.16	square inches	in^2
m^2	square meters	1.2	square yards	yd^2
km^2	square kilometers	0.4	square miles	mi^2
ha	hectares (10,000 m^2)	2.5	acres	
		MASS (weight)		
g	grams	0.035	ounces	oz
kg	kilograms	2.2	pounds	lb
t	tonnes (1,000 kg)	1.1	short tons	
		VOLUME		
ml	milliliters	0.03	fluid ounces	fl oz
l	liters	2.1	pints	pt
l	liters	1.06	quarts	qt
l	liters	0.26	gallons	gal
m^3	cubic meters	35	cubic feet	ft^3
m^3	cubic meters	1.3	cubic yards	yd^3
		TEMPERATURE (exact)		
°C	Celsius temperature	9/5 (then add 32)	Fahrenheit temperature	°F



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This report presents the results of an assessment of decentralized small cogeneration application for Navy shore facilities. For the purpose of this study, small cogeneration includes packaged, preengineered cogeneration systems with electric generating capacities below about 500 kW. The characteristics of the available small cogeneration equipment

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are collected and summarized. The available energy use data on hospitals, unaccompanied enlisted personnel housing (UEPH) and unaccompanied officer personnel housing (UOPM) at four Navy bases are analyzed. A method for applying small cogeneration equipment to such facilities is developed and used. The energy and economic characteristics of these applications are summarized and discussed. Four economically attractive decentralized small cogeneration applications are identified.

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1. INTRODUCTION

As part of an effort to reduce energy consumption, the Navy is examining new energy conservation technologies, one of which is small cogeneration. For the purpose of this study, small cogeneration refers to cogeneration equipment with electric generating capacities less than about 500 kW. This capacity is at the small end of the range of available cogeneration equipment and the small size is the unusual feature of the cogeneration equipment.

Most Navy bases have central plants which produce steam for distribution to the various base buildings. Some of these central plants cogenerate heat and electricity. In the context of this report, decentralized small cogeneration means cogeneration at the building or building complex where the cogenerated heat is used in contrast to cogeneration at the central plant. This focus on decentralized cogeneration has the important result that it makes the heat use characteristics of the building of critical importance.

The purpose of this study was to make a preliminary assessment of the suitability and economic value of decentralized small cogeneration. Three common Navy building types — hospitals, unaccompanied enlisted personnel housing (UEPHs, previously called BEQs), and unaccompanied officer personnel housing (UOPHs, previously called BOQs) — were examined for this preliminary assessment. Since climate, fuel prices, and energy supply systems differ at various Navy bases, buildings at four Navy bases were examined. The four Navy bases were located at Pensacola, Florida; Millington, Tennessee; Groton, Connecticut; and Point Mugu, California.

Cogeneration has long been used in industry where electricity and process heat are needed. The 1960s saw the introduction of the total energy (TE) concept. Total energy involves using cogeneration with back-up boilers to provide all the heat, cooling, and electricity required by a building or cluster of buildings. Since most TE installations predate the Public Utility Regulatory Policies Act of 1978 (PURPA), they generally had stand-alone generating capacity sufficient to meet all the electrical needs of the building or buildings connected to the TE plant. This stand-alone requirement led to the installation of multiple generators and excess capacity which would not have been necessary if hookup to the local electric utility had been allowed.

The Jersey City, New Jersey, TE demonstration is a good example of the TE concept.[1] Total energy was selected for the Jersey City site because it was expected to have lower life cycle cost than the conventional system. Natural gas was originally considered; however, the local public utility (which provides both electricity and natural gas) refused to provide gas to the site unless each apartment was individually metered for gas. This would have precluded the use of cogeneration, so No. 2 fuel oil was selected. The TE plant requires three 600-kW generators to meet the peak electric load. To provide reliable service, two additional 600-kW generators were also installed so that there would be one back-up generator even if one generator were being serviced. This TE plant has been operating reliably for several years. Conventional systems would use 24 to 88% more energy than the TE plant to provide the required service. Life cycle cost analysis shows that, in spite of the good performance, the additional investment required for TE pays for itself slowly (the simple payback period is greater than ten years).

Recent interest in small cogeneration has grown out of the combined influences of the very high electricity and fuel prices in some locations, the new federal investment tax credits, newly allowed accelerated depreciation, and the opportunities for attractive buy/sell arrangements with electric utilties since the enactment of PURPA. An example of a recent small cogeneration application uses the 60-kW Thermo Electron cogeneration module at a Dobbs House food preparation facility in Hawaii. The cogenerated heat is used for dishwashing and domestic water heating. The facility operates two 8-hour shifts, seven days per week. With a 1900 gal hot water storage tank, the cogeneration module will operate about 6000 hours per year. The cogeneration module is owned and operated by Pacific Resources, Inc. and the savings are shared with Dobbs House. The simplicity of the application allows the cogeneration module to operate nearly full time. Since the cogeneration module is not required to provide all the electricity required by the food facility, the capital cost is held down while good use is made of the equipment.

The Gas Research Institute (GRI) has an ongoing program of studies on small gas-fired cogeneration, several of which have been completed. One study set out to evaluate the requirements for a pre-engineered, packaged, gas-fired cogeneration system for medium-sized hospitals.[2] This study found that the average electric base load was 206 kW/bed. The study concluded that 300- and 450-kW internal combustion cogeneration modules could find wide use in supplying base load heat and electricity to hospitals. The report on this study does not provide much detail on how the cogenerated heat would be used. A planned follow-on study wherein a cogeneration module will be installed and tested may resolve some of the uncertainty about thermal energy use.

Another study considered cogeneration for fast-food restaurants. The study reported peak non-HVAC electricity consumption rates of 60-70 kW for these businesses.[3] To avoid large sales of excess electricity to the electric utility, a 70-kW internal combustion cogeneration module was selected. The design envisioned is a thermal load-following system which meets most of the space heating and cooling with cogenerated heat. Cooling is accomplished with an absorption chiller. A follow-on study wherein one of these modules will be built and used is planned.

A recently completed study evaluated the market for a 500-kW packaged cogeneration system built around a new high-efficiency gas turbine which has been developed by AiResearch Manufacturing Company.[4] The new gas turbine (model 601) is substantially more efficient than the existing turbine (model 831). The analysis found several applications with after-tax payback periods of less than three years.

An earlier study assessed cogeneration systems for residential and commercial applications.[5] This study gave extensive consideration to thermal energy storage to increase the value of cogeneration systems. The study found that cogeneration was economically attractive for a large number of applications, provided fuel prices were not too high and electricity prices were not too low.

GRI has several other studies in the planning stages. A study to develop a 100- to 200-kW packaged cogeneration unit to power lighting and refrigeration loads and produce space heating and dehumidification for supermarkets is planned. A low-cost controller capable of making economic operating decisions and analyzing trends in equipment parameters to optimize maintenance is to be developed and tested. Development of a variable-speed, constant-frequency alternator is planned to allow the prime mover to follow loads more efficiently. An effort is planned to determine the reliability, maintenance, and life of small, 1800-rpm reciprocating gas engine cogeneration packages.

There is a history of competition between suppliers of energy in different forms. The "All Electric Home" promotion is an example of the efforts of the electric utilities to capture a larger share of the residential energy market. With electricity prices at relatively high levels in much of the country, some natural gas companies are promoting cogeneration since it will increase their gas sales. With electricity sales leveled off, most electric utilities are naturally not enthusiastic about cogeneration. However, PURPA was enacted to ensure that cogenerators receive just, reasonable, and nondiscriminatory prices for sales of electricity to utilities.

There are four principal parts to this assessment. The characteristics of the small cogeneration modules presently available are summarized in Sect. 2, where some of the auxiliary equipment such as heat storage equipment are discussed as well. Characteristics of examples of tne three building types found at the four Navy bases are described in Sect. 3. Section 4 describes the method for and results of matching cogeneration modules to the various buildings. Section 5 gives the economic and financial characteristics of the cogeneration-building matches described in Sect. 4. Section 6 summarizes the results and conclusions of the study. Recommendations are given n Sect .

2. COMMERCIALLY AVAILABLE COGENERATION EQUIPMENT

Cogeneration equipment is available with a virtually unlimited range of characteristics. Manufacturers will assemble engines, generators, and heat exchangers to meet a customer's specific requirements. This is the usual procedure for large installations (above a few megawatts). However, for the small applications studied here, several of which are below 100 kW in size, the engineering of the custom cogeneration equipment adds significantly to its cost. Also, custom designs can be expected to have unique operating and maintenance requirements which are acceptable in large installations but which may be prohibitively expensive in the small applications.

For the above reasons, the scope of this study was restricted to preengineered, packaged cogeneration modules. Also, since the Navy is interested in near-term application of small cogeneration, advanced cogeneration technologies such as Stirling engines, organic Rankine cycle turbines, fuel cell systems, and solar thermal power systems were excluded from this study.

2.1 Characteristics of Commercially Available Cogeneration Modules

There is a considerable variety of cogeneration modules available, as shown on Table 2.1. Waukesha Engine Servicenter, Inc. (WESI), offers the smallest modules, with electric generating capacity as small as 15 kW. Martin Cogeneration Systems offers a large variety of units in sizes above 200 kW, including some units larger than 500 kW which are not included here. Costs range from about $600/kW to near $2000/kW. Induction generators are found on the smaller sized modules, but synchronous generators are generally the norm in the larger modules.

Table 2.1. Summary data on available small cogeneration modules

Manufacturer, model	Fuel type	Generator type	Electric capacity (kW)	Heating capacity (10^3 Btu/h)	Approx. Min installed cost ($)	Estimated maintenance cost (¢/kW)
Thermo Electron Corp.						
cogeneration module	gas	induction	60	440	40,000	1.5¢
Waukesha Engine Servicenter						
VRG 155/15	gas	induction	15	131	27,000	1.0
VRG 220/30	gas	induction	30	190	30,000	1.0
VRG 330/45	gas	induction	45	270	35,000	1.0
F817G/75	gas	induction	75	420	45,000	1.0
F1197G/105	gas	induction	105	632	70,000	1.0
F1905G/175	gas	induction	175	938	105,000	1.0
Cogenic Energy Systems						
M-100 GWI	gas	induction	100	630	110,000	1.5
M-100 GWS	gas	synchronous	100	630	120,000	1.5
M-120 DWI	oil	induction	120	765	110,000	2.0
M-120 DWS	oil	synchronous	120	765	120,000	2.0
M-400 GWS	gas	synchronous	450	2150	290,000	1.5
M-400 DWS	oil	synchronous	400	2040	290,000	2.0
Martin Cogeneration Systems						
3408 DI-T-JWAC	oil	synchronous	275	1120	320,000	1.5
3412 DI-T-JWAC	oil	synchronous	330	1220	360,000	1.5
3912 DI-TT-JWAC	oil	synchronous	460	2040	370,000	1.5
3508 DI-TT-JWAC	oil	synchronous	430	1820	400,000	1.5
G379 NA-HCR	gas	synchronous	230	1340	380,000	1.0
SCAC-LCR	gas	synchronous	300	1780	400,000	1.0
G398 NA-HCR	gas	synchronous	350	2050	440,000	1.0
SCAC-LCR	gas	synchronous	450	2550	460,000	1.0
G399 NA-HCR	gas	synchronous	460	2620	480,000	1.0

2.1.1 Manufacturer's approaches

Thermo Electron Corporation's cogeneration module is built around a methane-modified 454-CID, V8 Chevrolet gasoline engine with which they have had experience in marine applications. The engine is fairly inexpensive and intended to be replaced at fairly frequent intervals. The induction generator, coupled directly to the drive shaft, controls the engine speed to 1800 rpm. The chassis, enclosure, heat exchanger, and controls were designed expressly for this unit. The intended mode of operation is either on (approximately 60 kW) or off. The module is capable of being operated at lower capacities, but its efficiency declines significantly below 60 kW.

The on-off approach assumes that the load will be able to absorb all the heat output of the unit; if the load does not absorb the required heat, the module automatically shuts down. This on-off approach allowed Thermo Electron to eliminate the radiator and to design for indoor installations.

WESI builds cogeneration modules around Waukesha engine-generator sets. Each engine-generator set includes a radiator with engine-driven fan. The generator is an open type, so it needs to be kept in a reasonably clean environment. For cogeneration, an exhaust gas-to-engine coolant heat exchanger and an engine coolant-to-water heat exchanger are added. Also, one of two options with the radiator must be taken. The simplest and preferred option, where electricity is not valuable enough to pay for operation of the module without use of the waste heat, is on-off operation without use of a radiator. Where electricity is very valuable, the engine-driven fan can be replaced by an electric motor driven fan and a control system that directs engine coolant through the radiator only when necessary to keep the engine cool enough. The WESI modules reported here assume the former option and include a weather-protective housing and a silencer to keep module noise to 65 dBa at 3 m.

Cogenic Energy Systems modules are powered by Caterpillar engines. All modules operate at 1800 rpm except the M-450 GWS, which operates at 1200 rpm. Unlike the Thermo Electron module, they are equipped with a radiator which allows the module to generate at full electricity capacity even when the thermal load cannot accept any heat. These units are intended for placement out-of-doors.

Martin Cogeneration Systems designs its modules for high reliability and long life at a relatively high price. Martin is a Caterpillar dealer, and all its modules are built around Caterpillar engines. By using various engines, engine speeds, and aspiration methods they have developed a wide and overlapping range of modules. Each of these modules is housed in one of their two enclosures. Like Cogenic's enclosures, these enclosures include a radiator to allow operation without a thermal load. The Martin enclosures are more elaborate than those of Thermo Electron, WESI, or Cogenic in that they are designed to allow a man to walk around in them and they include a control room.

2.1.2 Energy Characteristics

These cogeneration modules have electric generating heat rates between 12,000 and 14,000 Btu/kWh except the WESI VRG 155/15 with a 19,300-Btu/kWh heat rate. The larger units are generally more efficient than the smaller units (Table 2.2). The modules are designed to use either No. 2 diesel fuel or natural gas. Most natural gas-fired modules will also use propane. WESI modules can use a variety of gaseous fuels. Presumably, the other natural gas engines can use or could be modified to use other gaseous fuels.

The heating capacities of the modules are approximately proportional to their electric generating capacities (Table 2.2). The input and output temperature capabilities of the modules are somewhat different. The 250°F maximum output temperature of the Thermo Electron module is considerably higher than that of the other modules. In fact, the 210°F minimum output temperatures is higher than the maximum output temperatures of the other modules. This high minimum output temperature is necessary to avoid condensing the exhaust gases. These high output temperature are of advantage in driving absorption air conditioning equipment and for minimizing heat exchanger sizes.

Table 2.2. Energy production and consumption of available small cogeneration modules

Manufacturer, model	Fuel type	Electric capacity (kW)	Fuel rate	Heating capacity (10^3 Btu/h)	Heat-to-electric ratio	Min/Max output temperature (°F)	Min/Max input temperature (°F)
Thermo Electron Corp. cogeneration module	gas	60	760 ft^3/h	440	2.1	210/250	160/180
Waukesha Engine Servicenter							
VRG 155/15	gas	15	290 ft^3/h	131	2.6	none/205	none/175
VRG 220/30	gas	30	420 ft^3/h	190	2.0	none/205	none/175
VRG 330/45	gas	45	600 ft^3/h	270	1.8	none/205	none/175
F817G/75	gas	75	940 ft^3/h	420	1.7	none/205	none/175
F1197G/105	gas	105	1350 ft^3/h	623	1.8	none/205	none/175
F1905G/175	gas	175	2290 ft^3/h	938	1.6	none/205	none/175
Cogenic Energy Systems							
M-100 GWI	gas	100	1250 ft^3/h	630	1.8	none/200	none/180
M-100 GWS	gas	100	1250 ft^3/h	630	1.8	none/200	none/180
M-120 DWI	oil	120	9.6 gal/h	765	1.9	none/200	none/180
M-120 DWS	oil	120	9.6 gal/h	765	1.9	none/200	none/180
M-400 GWS	gas	450	5625 ft^3/h	2040	1.3	none/230	none/180
M-400 DWS	oil	400	36.0 gal/h	2150	1.4	none/230	none/180
Martin Cogeneration Systems							
3408 DI-T-JWAC	oil	275	20.0 gal/h	1120	1.2	none/205	none/190
3412 DI-T-JWAC	oil	330	23.3 gal/h	1220	1.1	none/205	none/190
3412 DI-TT-JWAC	oil	460	33.4 gal/h	2040	1.3	none/205	none/190
3508 DI-TT-JWAC	oil	430	30.6 gal/h	1820	1.2	none/205	none/190
G379 NA-HCR	gas	230	2776 ft^3/h	1340	1.7	none/205	none/190
SCAC-LCR	gas	300	3797 ft^3/h	1780	1.7	none/205	none/130
G398 NA-HCR	gas	350	4079 ft^3/h	2050	1.7	none/205	none/190
SCAC-LCR	gas	450	5600 ft^3/h	2550	1.7	none/205	none/130
G399 NA-HCR	gas	460	5560 ft^3/h	2620	1.7	none/205	none/190

However, the relatively low input temperature can be a disadvantage in some cases. The 130°F input temperatures required by some of the Martin gas modules may somewhat reduce the amount of thermal energy actually recoverable in certain applications. The Martin modules with G379 and G398 SCAC-LCR engines require the low input temperature to cool the aftercoolers.

All the input and output temperatures on Table 2.2 are for the engine/exhaust gas heat exchanger. In all cases, there will be an heat exchanger between the loop which cools the engine and recovers heat from exhaust gases and the loop which supplies heated water to the intended use. Consequently, the temperatures of the heated water will necessarily be lower. Typically, heat exchangers will have a 20°F temperature difference between one side and the other, but this can be changed somewhat by system design.

2.1.3 Installation Costs and Requirements

Minimum installation costs are on the order of 10% of the module cost (Table 2.3). Since most applications of these units are in retrofit situations, costs can easily be much higher, perhaps as high as 50% of the module cost. In most applications, the synchronous generator modules require an additional utility connection package to allow operation in parallel with the utility. These connection packages seem to start at about $8,000-12,000 and go up in certain regulatory environments. All these modules are designed for 480 V, three phase (Table 2.4). Other voltages are available but at a higher price.

The Thermo Electron Cogeneration module is designed for indoor use. It is also intended for ground level placement where easy access is possible to allow quick replacement and factory rebuilding of the engine at its relatively frequent 8000-h overhaul. The Cogenic and Martin modules are both designed for outdoor placement. Their placement is not so restricted since they are designed for less frequent overhauls and, because of the size of the engines, overhauls must be done on-site, not at the factory.

Table 2.3. Installation costs for available small cogeneration modules.

Manufacturer, model	Electric capacity (kW)	FOB cost ($)	Required auxiliaries cost ($)	Minimum installation cost ($10^3)	Minimum total cost ($10^3)	Approximate cost ($/kW)
Thermo Electron Corp.						
cogeneration module	60	35,000	none	5-10	45	750
Waukesha Engine Service Center						
VRG 155/15	15	22,277	none	5-10	27	1,800
VRG 220/30	30	22,616	none	5-10	30	1,000
VRG 330/45	45	25,704	none	5-10	35	780
F817G/75	75	41,258	none	10-15	50	670
F1197G/105	105	58,478	none	10-15	70	670
F1905G/175	175	90,285	none	10-20	105	600
Cogenic Energy Systems						
M-100 GWI	100	100,000	none	10-20	110	1,100
M-100 GWS	100	100,000	8,000	10-20	120	1,200
M-120 DWI	120	100,000	none	10-20	110	920
M-120 DWS	120	100,000	8,000	10-20	120	1,000
M-400 GWS	450	260,000	8,000	10-20	290	580
M-400 DWS	400	260,000	8,000	20-40	290	730
Martin Cogeneration Systems						
3408 DI-T-JWAC	275	280,328	12,000	28*	320	1,160
3412 DI-T-JWAC	330	315,214	12,000	32	360	1,090
3412 DI-TT-JWAC	460	321,613	12,000	32	370	800
3508 DI-TT-JWAC	430	348,864	12,000	35	400	930
G379 NA-HCR	230	333,814	12,000	33	380	1,650
SCAC-LCR	300	355,993	12,000	37	405	1,650
G398 NA-HCR	350	383,770	12,000	38	440	1,260
SCAC-LCR	450	406,740	12,000	41	450	1,020
G399 NA-HCR	460	425,044	12,000	43	480	1,050

*Installation costs for Martin modules are based on an assumed minimum installation cost of 10% of the FOB cost.

Table 2.4. Installation requirements for available small cogeneration modules

Manufacturer model	Electricity capacity (kW)	Voltages*	Generator type	Required auxiliaries	Approximate dimensions L x W x H (ft)	Noise level	Access Requirement
Thermo Electron Corp.							
cogeneration module	60	480/277 or 208/120	induction	none	7 x 4 x 4	66 dBA at 6 m	Ground level drive-up
Waukesha Engine Servicenter							
VRG 155/15	15	240	induction	none	6 x 3 x 6	85 dBA at 3 m	None
VRG 220/30	30	240	induction		7 x 3 x 5	is standard.	specified
VRG 330/45	45	240	induction		8 x 3 x 5	An inexpensive	
F817G/75	75	480	induction		10 x 4 x 6	silencer is	
F1197G/105	105	480	induction		10 x 4 x 7	available to	
F1905G/175	175	480	induction		12 x 5 x 8	achieve 65 dBA at 3 m.	
Cogenic Energy Systems							
M-100 GWI	100	480/277 or 208/120	induction	none	12 x 6 x 8	per spec.	Designed for
M-100 GWS	100	480/277 or 208/120	synchronous	utility package	12 x 6 x 8		
M-120 DWI	120	480/277 or 208/120	induction	none	12 x 6 x 8		placement
M-120 DWS	120	480/277 or 208/120	synchronous	utility package	12 x 6 x 8		
M-400 GWS	450	480/277 or 208/120	synchronous	utility package	16 x 18 x 9		
M-400 DWS	400	480/277 or 208/120	synchronous	utility package	16 x 10 x 8		
Martin Cogeneration Systems							
3408 DI-T-JWAC	275	480 or other	synchronous	utility	40 x 10 x 11	mid 70 dBA +	Designed for
3412 DI-T-JWAC	330	480 or other	synchronous	intertie	40 x 10 x 11	mid 70 dBA +	outdoor
3412 DI-TT-JWAC	460	480 or other	synchronous	package	40 x 10 x 11	(Mid 70 dBA	placement
3508 DI-TT-JWAC	430	480 or other	synchronous		40 x 10 x 11	is the minimum sound level.	
G379 NA-HCR	230	480 or other	synchronous		40 x 10 x 11	When heat is	
SCAC-LCR	300	480 or other	synchronous		40 x 10 x 11	being dissipated	
G398 NA-HCR	350	480 or other	synchronous		47 x 12 x 11	by the radiator	
SCAC-LCR	450	480 or other	synchronous		47 x 12 x 11	the sound level	
G399 NA-HCR	460	480 or other	synchronous		47 x 12 x 11	is increased)	

*The prices shown on Table 2.3 are based on the higher voltage shown. Lower voltage generators cost extra.

The Thermo Electron module's enclosure and its lack of a radiator and fan make it especially quiet. In applications which require inclusion of a radiator this relative quietness will likely be lost. Also, in applications where a radiator is required the radiator cost should be considered an additional installation cost. The Cogenic and Martin modules include radiators, so they are not a part of the installation cost. The WESI modules are converted emergency generators, so they include radiators; however, the radiators can be left off for a small credit. An inexpensive silencer ($100 for the VRG 220/30) is available to reduce the sound level to 65 dBA at 3 m.

2.1.4 Maintenance Requirements

Expected service intervals range from 250 to 1000 h (Table 2.5). These values are those reported to us by the manufacturers. The large Cogenic modules use some of the same Caterpillar engines used by Martin in their modules, but the two manufacturers quote rather different service intervals.

The major overhaul interval of the Thermo Electron module engine is relatively short at 8000 h. In spite of this, the maintenance contract cost is competitive with those units with longer overhaul intervals. Thermo Electron expects to keep maintenance costs down by replacing the engine with a new or rebuilt engine at 8000 h and rebuiding the old engine in their factory. WESI quotes quite long duration service and overhaul intervals for their small 1800-rpm modules. It would not be surprising if shorter intervals were required under field conditions. The more expensive and longer lived Caterpillar engines require major work less often, but the work will probably be done on-site at a high cost.

Thermo Electron, WESI, and Cogenic offer maintenance contracts on their modules. Martin does not offer such contracts; however, engine service can be obtained from local Caterpillar dealers. Maintenance of switch gear, generators, and controls is presumably obtained from the respective manufacturer. The lack of a simple service arrangement can be a disadvantage to a prospective module purchaser. On the other

Table 2.5. Maintenance characteristics of available small cogeneration modules

Manufacturer, model	Electric capacity (kW)	rpm	Service interval (h)	Overhaul interval (10^3 h)	Maintenance contract available	Estimated maintenance cost (¢/kWh)	Notes
Thermo Electron Corp.							
cogeneration module	60	1800	500	8	yes	1.5	Service through Challenger dealers
Waukesha Engine Servicenter							
VRG 155/15	15	1800	750	18-24	yes	1.0	
VRG 220/30	30	1800	750	18-24		1.0	
VRG 330/45	45	1800	750	18-24		1.0	
F817G/75	75	1200	750	18-30		1.0	
F1197G/105	105	1200	750	18-30		1.0	
F1905G/175	175	1200	750	18-30			
Cogenic Energy Systems							
M-100 GWI	100	1800	250-400	15-18	yes	1.5	
M-100 GWS	100	1800	250-400	15-18		1.5	
M-120 DWI	120	1800	250-400	15-18		2.0	
M-120 DWS	120	1800	250-400	15-18		2.0	
M-400 GWS	450	1200	$\geq$ 500	30*		1.5	
M-400 DWS	400	1800	$\geq$ 250	20		2.0	
Martin Cogeneration Systems							
3408 DI-T-JWAC	275	1800	500	20	no**	1.5**	Engine service through Caterpillar dealers
3412 DI-T-JWAC	330	1200	500	24			
3412 DI-TT-JWAC	460	1800	500	20			
3508 DI-TT-JWAC	430	1200	500	24			
G379 NA-HCR	230	1200	1000	40	no**	1.0**	
SCAL-LCR	300	1200	1000	40			
G398 NA-HCR	350	1200	1000	40			
SCAC-LCR	450	1200	1000	40			
G399 NA-HCR	460	1200	1000	40			

*Valve grinds at 10,000 and 20,000 h.

**Martin does not offer a maintenance contract, but their representative, Mike Godenkauf, estimated they could provide a contract at or below these prices.

hand, if Navy personnel are available to perform the required service, then maintenance costs may be less than under a maintenance contract.

2.1.5 Reliability

Reliability is a matter of great concern and even greater uncertainty for small cogeneration systems. Small cogeneration systems are relatively new, so experience with these systems is limited. Gamze gives a summary of experience with total energy systems, much of which is relevant to small cogeneration systems.[6] Gamze reports that prime mover failure rates depend more on design and manufacturer than on maintenance. A large variety of minor component failures have caused engine failures in cogeneration applications. Gamze also reports that the lives of slower speed engines is not materially greater than the lives of 1200-rpm engines for sizes below 3-4 MW. He gives no information on 1800-rpm engines.

Few small cogeneration systems assembled by Martin, WESI, Cogenic, and Thermo Electron have been installed, so there is little operating experience to go by. Before the Navy embarks on a large program of small cogeneration use, more experience with this equipment is essential. After some of the recently installed small cogeneration modules have operated a year or two there may be some anecdotal information. Better data on small cogeneration reliability could be gained by a few well-designed demonstrations.

2.1.6 Summary

In selecting a cogeneration module, size is the first concern. Martin has a good selection of modules in the 200- to 500-kW range. WESI has a selection of modules below 200 kW. Thermo Electron's 60-kW module and Cogenic's 100- and 120-kW modules provide options in the less than 200-kW size range. Cogenic's 400-kW modules provide options in the above-200-kW range.

The small sizes and low costs of the Thermo Electron and WESI modules will make them attractive where the larger cogeneration modules would be inappropriate. The larger modules made by Cogenic and Martin seem to be aimed at a different market where reliable electric power is needed and stand-alone capabilities are important. In the larger sizes, there is apparently little difference between the costs of synchronous and induction generator/switchgear sets. Where emergency electric power generation is required, the extra costs of premium quality cogeneration equipment may be justified by the elimination of emergency generators which need not be bought.

2.2 Other Small Cogeneration Equipment

As mentioned above, a wide variety of small cogeneration systems can be assembled. The California Energy Commission published a "Cogeneration Equipment Compendium" which presents information on a variety of engines (large and small) that can be adapted to cogeneration.[7] The Gas Research Institute is soon to publish a survey of small engines which might be used for cogeneration.

All the cogeneration modules discussed in Sect. 2.1 and all of the small engines surveyed by GRI are internal combustion engines. Gas turbines are a well-developed type of prime mover, but most combustion turbine-generator sets have capacities over 500 kW. One exception is Alturdyne, a California company which supplies gas turbine/ generator sets with capacities below 200 kW. Alturdyne does not supply heat recovery equipment for their generator sets and no one presently builds cogeneration modules around their turbines.

Aurther D. Dietrich Company (ADCO) builds electric generator sets around the Garrett Corporation's Model 831-800 gas turbine. ADCO's generator sets range in capacity from 300 kW to one set with a standby capacity of 550 kW. ADCO does sell heat recovery equipment for their generator sets but does not market cogeneration modules. With heat recovery and utility-paralleling equipment, one of ADCO's generator sets will run $450,000-500,000. Essentially, the only difference between the 300-kW and the 550-kW generator sets is the size of the electric generator supplied; as a result, the cost difference between the largest and smallest generator set is about $40,000. The ONAN Corporation sells a generator set built around the 831 turbine and also offers heat recovery equipment.

2.3 Thermal Energy Storage

In most cases the economic viability of small cogeneration depends on full utilization of the cogenerated heat and electricity. Operation of the cogeneration module in parallel with the electric utility system allows the module to run independent of the electric load of the building at which it is located. The same is not true of the heat produced by the cogeneration modules. Because of the low temperature of the heat cogenerated by the modules (Table 2.2), the heat must be used by the building at which the module is located. Except where the heat load is very steady, some thermal energy storage device is needed as a buffer between the steady heat ouput of the cogeneration module and the variable heat load.

A number of thermal energy storage systems have been proposed, but the simplest and cheapest method is to store hot water at temperatures below 212°F in an insulated tank. The cost of insulated hot water storage tanks is highly variable depending on insulation level, lining, location, and temperature and pressure requirements.[8] We made calls to a local tank distributor to get estimates on insulated potable water storage tanks. We were given a price on a used, nonpressurized, stainless steel tank which had been used for milk storage (telephone communication with Mr. Jim Brinks of Brinks Tanks, Knoxville, Tennessee, June 17 and 18, 1983). Tanks of this type are horizontal, 8 1/2 ft in diameter, and have 4 in. of insulation and a painted mild steel shell. Including sandblasting and primer painting the mild steel shell, the FOB cost is $1.30 per gal. We have assumed that freight and installation would add $0.50 per gal to this cost. This is not a pressure tank. New tanks such as these would cost $2.00-2.50 per gal.

While a stainless steel tank is certainly not needed for this purpose, a new insulated mild steel tank with a phenolic lining is not expected to cost much, if any, less than these used tanks.

As noted, the $1.30 per gal is based on use of a tank which is not intended to be pressurized. We chose to use nonpressurized tanks because pressure tanks cost considerably more. Since most of the cogeneration modules discussed here produce hot water at temperatures lower than about 205°F and most of the uses do not require water hotter than approximately 190°F, vented nonpressure tanks should be adequate.

The heat storage capacity of a hot water storage tank depends on the volume of the tank, the operation of the tank, and the difference between the storage temperature and temperature of the water supplied to the cogeneration module. Approximately 8.3 Btu per °F temperature difference can be stored in a gallon of water. For example, if the city water supply temperature is 60°F and it is stored at 180°F then a 1000-gal tank has a capacity of about one million Btu (8.3 Btu/gal-°F x 120°F x 1000 gal). If the storage tank is used for a hydronic heating system with a 60°F difference between outlet and inlet temperatures, then the same 1000-gal tank would have a capacity of about 0.5 million Btu (8.3 Btu/gal-°F x 60°F x 1000 gal).

These energy storage capacities presume that the storage tank is filled to store energy and emptied to retrieve the stored energy. The hot water stored in the tank is city water which was heated to the storage temperature (say 180°F) by the cogeneration module. The stored hot water is then used directly for potable hot water applications. This is the operation method assumed in the remainder of this report; however, there is another operation method sometimes used for hot water thermal energy storage. This other method keeps the tank full and usually pressurized. Cool water is withdrawn from and added to the tank at the bottom, and hot water is added to and withdrawn from the top of the tank. This operation method results in a lower thermal energy storage capacity because the hot and cool water inevitably mix in the tank. Since there is always some minimum useful hot water temperature (say, for space heating) and some maximum acceptable cool water temperature (for cooling the cogeneration module) there is always some volume of water which does not store useful energy. We have assumed that this thermal energy storage system is not used.

3. APPLICATION CHARACTERISTICS

3.1 General Building Characteristics

One of the first steps of the project was to select the building types that suited the applications for small decentralized cogeneration. The Navy has several types of building categories, and the selection for this study was limited to three types that are usually present on Navy bases. The three potential applications are: (1) unaccompanied officer personnel housing (UOPH), (2) unaccompanied enlisted personnel housing (UEPH), and (3) hospitals. Data for the applications were gathered from four Navy bases-- Millington, Tennessee; Pensacola, Florida; Point Mugu, California; and Groton, Connecticut. The data gathered at these bases include physical descriptions of the buildings, descriptions of the heating and air conditioning systems, energy consumption, and energy costs. This section will provide an overview of the physical description of the building and the existing equipment. Subsequent sections describe the energy consumption and energy cost.

3.1.1 Unaccompanied Enlisted Personnel Housing

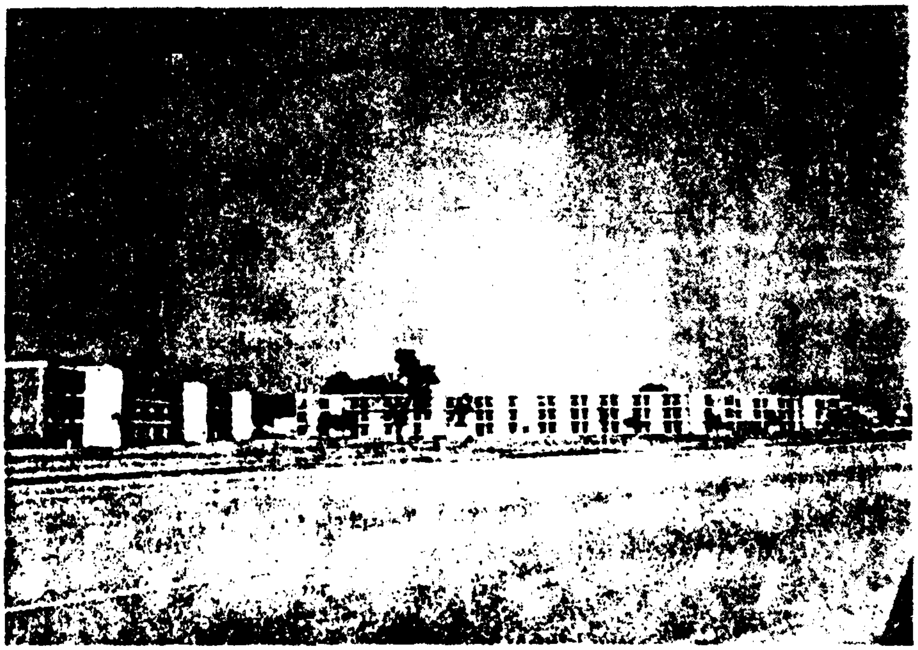
The UEPHs exist in a variety of forms. This study considered the modern facilities, those built after 1960; however, modern modular barracks were not studied. Usually, the UEPH complexes consist of one to five buildings, and each building is three to five stories high. The buildings are of poured concrete construction with a brick siding and are of medium to heavy construction. The UEPH complexes house between 400 and 1200 people. Details on the complexes are provided in Table 3.1-a. The square footage per occupant varied between 150 and 200 ft^2 per person. The apparent trend is: the more modern the building, the more square footage per person. Pictures of two UEPHs are shown in Fig. 3.1. At both of these complexes, the buildings are three stories high and consist of a set of three to five buildings.

Table 3.1-a Navy building complex characteristics

	Floor area (ft^2)	Occupancy (design/average)	Location of mechanical equipment room	Type heating system (capacity)	Type cooling system	Distribution system between or inside buildings	Potable water
UEHP*							
Millington, Tenn. Building No.							
435	21,081	123/195		Heat exchanger connected to base's central steam system (1.824×10^6 Btu/h)	Absorption chillers using 12 psig steam from base's central steam system 2.58×10^6 Btu/h)	Two-pipe water system between buildings: 1. circulates 190°F hot water in heating season 2. circulates 45°F chilled water cooling season; manual switch over between seasons	Two heat exchangers connected to base's central steam system and two storage tanks (the heat exchangers are 1.8×10^6 Btu/h each)
436	21,081	123/195					
437 (1-floor community bldg.)	1,965		Rear part of 437				
438	21,081	123/195					
439	21,081	123/195					
440	21,081	123/195					
five of bldgs. have 3 floors	107,370	615/975					
Pensacola, Fla. Building No.							
3468	33,150		Bldgs. 3468 through 3470 have a common equipment room which is attached to 3469	Heat exchanger connected to base's central steam system	Absorption chiller using 15 psig steam from base's central steam system	Two-pipe water system between buildings: 1. circulates 190°F hot water in heating season 2. circulates 45°F chilled water in cooling season	Heat exchanger connected to base's central steam system and storage tank (the heat exchangers are 0.6×10^6 Btu/h)
3469	26,515						
3470	33,150						
3471	33,150		Bldgs. 3470 through 3475 have a common equipment room which is attached to 3472				
3472	33,150						
3473	26,815						
3474	29,000						
3475	29,000						
All bldgs. have 3 floors	244,230	1165/1165					
Groton, Conn. Buidling No.							
488 Two wings each five floors	100,000	600/600	First floor at the end of the wings	Two heat exchangers connected to base's central steam system (0.75×10^6 Btu/h each)	Centrifugal chiller (2.1×10^6 Btu/h)	Two-pipe water system between wings 1. circulates 190°F hot water in heating season 2. circulates 45°F chilled water in cooling season	Two heat exchangers connected to base's central steam system (6.0×10^6 Btu/h each)
Point Mugu, Calf. Building No.							
241	60,342	383/500	Basement of Bldg. 241	Gas boiler (1.37×10^6 Btu/hr)	None	Building has hydronic system. The two-pipe system circulates 200°F hot water in the heating season	Gas boiler and storage tank (1.5×10^6 Btu/h)

*Unaccompanied enlisted personnel housing.

Millington, Tennessee: 5-building complex, 615 people



Pensacola, Florida: 8-building complex, 1165 people

Fig. 3.1. Unaccompanied enlisted personnel housing (UEPH).

The complex at Pensacola could easily have been considered to be two complexes since there are two independent mechanical rooms. The two complexes are combined here to provide a larger parametric extreme. A similar situation exists in Millington, Tennessee; where there are several complexes of approximately 600-person capacity. Two or three of these could also be connected and tied in to a cogeneration energy source. The possibility for connecting groups of buildings at Groton and Point Mugu appeared much more difficult. The complexes were either not as close together or there were too many small UEPHs of 20- to 30-person capacity. Connection of the complexes is still technically feasible, however, the costs are higher than for connecting larger complexes together at Millington and Pensacola.

The heating systems in all four of these buildings are hydronic (water) systems. The systems have both supply and return pipes that circulate hot water during the heating season. The barracks at Millington, Pensacola, and Groton use the same piping system to circulate chilled water during the cooling season. The UEPH at Point Mugu has no space-cooling system because cooling is not required. Two-pipe water system are the norm for modern Navy barracks, where 190°F hot water is circulated in the heating season and chilled water is circulated through the same piping system during the cooling season.

The mechanical equipment rooms of three of the complexes are located at the ground level. Again, the exception is the barracks at Point Mugu, where the mechanical equipment room is located in the basement. The heat source for the barracks at Millington, Pensacola, and Groton is the base's central steam system. Steam is delivered to the mechanical equipment room and converted into hot water through a set of heat exchangers. Domestic hot water is also supplied through heat exchangers from the base's central steam system. Included in each domestic hot water system is a small storage tank; however, most of the capacity from the demand is supplied from the heat exchangers. The storage tanks only act as a buffer. For the barracks at Point Mugu there is a gas boiler and a storage tank. As mentioned previously, the

UEPH at Point Mugu is not connected to the base steam district heating system.

The cooling for the barracks is provided either by an absorption chiller that operates off low-pressure steam or an electrically driven compressive chiller. The low-pressure steam for the absorption chillers is provided from the base's central steam system. The chillers range in capacity from 150 tons to over 200 tons.

3.1.2 Unaccompanied Officer Personnel Housing

The UOPHs have a number of similiarities to the UEPHs (Fig. 3.2). They are of medium to heavy construction, mainly poured concrete with brick facing. They are heated and cooled by two-pipe hydronic distribution systems. Details on the complexes are provided in Table 3.1-b. The UOPH at Millington has a gas-fired boiler and a gas domestic water heater. The UOPH at Pensacola is similar to the UEPHs in that it is connected to the base's central steam system, and heat for space heating and potable hot water is from heat exchangers that interface with the base's central steam system.

The main difference between the UOPHs and the UEPHs is that the UEPHs are generally smaller in size and capacity. The UOPH at Pensacola is 115,000 ft^2 with a capacity of 260 people. The one at Millington is considerably smaller with 53,000 ft^2 and a capacity of 85 people. The UOPHs have at least twice the square footage per person as the UEPHs. The UOPHs range between 400 ft^2 per person to over 600 ft^2 per person, compared to approximately 200 ft^2 per person for a UEPH.

3.1.3 Hospitals

Navy hospitals are usually multistory buildings. Their locations are generally somewhat isolated from the remainder of the base. For example, in Groton the hospital is located at the top of a bluff. The three hospitals examined for this study (Millington, Pensacola, and

Millington, Tennessee: One rectangular building, 85 people

Pensacola, Florida: U-shaped building, 260 people

Fig. 3.2. Unaccompanied officer personnel housing (UOPH).

Table 3.1-b Navy building complexes characteristics

	Floor area (ft²)	Occupancy design/average	Location of mechanical equipment room	Type heating system, capacity	Type cooling system, capacity	Distribution system between or inside buildings	Potable water
Hospitals							
Millington, Tenn. Bldg. 100 6 floors	222,515	230 beds	Basement	Three natural gas-fired boilers, 10×10^6 Btu/h each 90 psig	One electrical centrifugal unit 4.2×10^6 Btu/h; one absorption chiller, 4.2×10^6 Btu/h	Hydronic parameter heating and steam air handlers	Two tank-type heat exchangers, 2,400 gal each, 1.6×10^6 Btu/h each
Pensacola, Fla. Bldg. 100 6 floors		230 beds	Adjacent but not attached to building	Three natural gas-fired boilers, 10×10^6 Btu/h each 100 psig	One absorption chiller, 7.7×10^6 Btu/h	Hydronic parameter heating and steam air handlers	Two tank-type heat exchangers
Groton, Conn. Bldg. 449 5 floors	150,000	125 beds	Heat exchanger in basement with cooling equipment located on 4th floor	Four heat exchangers connected to base's central steam plant, two 10×10^6 Btu/h for fan coil use, two 0.6×10^6 Btu/h for hydronic parameter heating	One absorption chiller, 6.5×10^6 Btu/h; Two electrical centrifugal units, 0.36×10^6 Btu/h	Hydronic parameter heating and hot water air handlers	Two tank-type heat exchangers, 750 gal each, 0.6 Btu/h each
UOPH*							
Millington, Tenn. Bldg. 599 3 floors	53,721	85/95	Second floor, back part of building	Gas-fired boiler, 3.0×10^6 Btu/h, oil used as backup fuel	Electrical centrifugal unit, 1.4×10^6 Btu/h	Two-pipe water system 1. circulates hot water in heating season 2. circulates chilled water in cooling season	Gas-fired water heaters 1.0×10^6 Btu/hr
Pensacola, Fla. Bldg. 3252 3 floors U-shaped bldg.	114,900	260	Basement at the end of one wing	Heat exchanger connected to base's central steam system, 2.6×10^6 Btu/h	Electrical centrifugal unit, 3.0×10^6 Btu/h	Two-pipe water system 1. circulates hot water in heating season 2. circulates chilled water in cooling season	Four tank-type heat exchangers connected to base's central steam system, 0.2×10^6 Btu/h each

*Unaccompanied officer personnel housing.

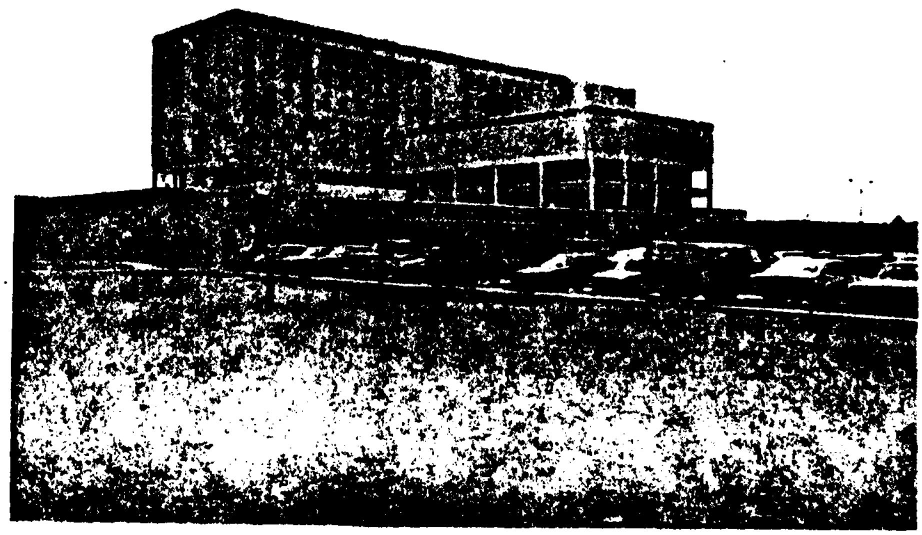
Groton) are medium in size, with 125-250 beds. The hospitals at Millington and Pensacola, each of which have over 200 beds, are larger than the one at Groton with 125 beds. There is no hospital at the base at Point Mugu. Pictures of the hospitals in Millington and Pensacola are given in Fig. 3.3

The hospitals at Millington and Pensacola each have three natural gas-fired boilers. The hospital at Groton is connected to the base's central steam plant. At Millington, the boilers and the HVAC equipment are located in the basement. The hospital at Pensacola has a building adjacent to the hospital that contains the boilers and the chillers. At Groton, the heat exchangers that interface with the base district heating system are in the basement; and the chiller is on the fourth floor. Details on the hospitals are provided in Table 3.1-b.

The boilers for the hospitals at Millington and Pensacola each produce approximately 100 psig steam. Steam is used directly in the air-handler ventilation system but is converted to hot water in a heat exchanger for perimeter heating throughout the building. For Groton, steam from the central steam system is converted to hot water for both the perimeter heating and for heat exchangers in the air-handling ventilation system. At Millington and Groton, the cooling is done by a combination of absorption chillers and centrifugal units. At Pensacola, the cooling is handled by a single, large absorption chiller that uses 12-15 psig steam which comes from either the boilers or the base's central steam system. The chillers range in size from 400 to 700 tons.

The source of energy for domestic hot water is steam, either from the gas boilers or, in the case of Groton from the base's central steam system. All three hospitals have tank-type heat exchangers that use low-pressure steam to heat domestic hot water. These are relatively small tanks of around 1000 gallons and, therefore, only act as buffers. The heat exchangers have capacities of 0.6 to 1.6 x 10^6 Btu/h.

Millington, Tennessee: 230 beds, 222,515 ft^2



Pensacola, Florida: 230 beds

Fig. 3.3. Navy hospitals.

3.2 Energy Consumption Characteristics

At each of the four bases, an attempt was made to gather energy-related data. For each of the three building types, the desired data included: (1) electric energy usage and electric demand, (2) steam usage and/or natural gas consumption, and (3) weather data such as heating degree-days (HDD). The main difficulty in obtaining these data is that the Navy usually does not meter individual buildings or building complexes. It would have been desirable to have some hourly energy consumption data, however, there was none available on any of these four bases. The data available from these bases were limited to monthly energy consumptions and electric demand in some cases.

3.2.1 Electricity usage

The UEPHs use electricity for lighting and other purposes. The barrack at Groton is the only one studied that uses electricity for air conditioning. At Millington and Pensacola, the UEPHs have absorption chillers, and at Point Mugu, there is no air conditioning. At Millington, the monthly usage ranges between 110,000 and 147,000 kWh. For Pensacola, which is a larger barrack, the range is between 132,000 and 288,000 kWh per month. On a per person basis, the range is between 120 and 250 kWh per person per month. The peak demand for electricity in the UEPHs is approximately 300 kW. Data on the annual electric energy usage are given in Table 3.2.

The Navy hospitals are larger users of electricity. The minimum monthly usage for the hospital at Millington is 450,000 kWh; and peak usage is 793,000 kWh. The peak occurs in the summer when using the 400-ton centrifugal compressor. For comparison, the hospital at Pensacola uses almost twice the electricity, with a minimum of 920,000 kWh and a maximum of 1,360,000 kWh per month. The peak demand for electricity at these hospitals ranges between 1200 and 2000 kW. The hospitals use about five times as much electricity as the UEPHs.

Table 3.2 Navy building energy use data

	Service voltage	Electrical energy usage Annual (10^6 kWh)	Electrical energy usage Monthly (high/low) (10^3 kWh)	Electrical demand (kW)	Space conditioning annual (10^0 Btu)	Space conditioning monthly (high/low) (10^6 Btu)	Hot water monthly (10^6 Btu)
UEPHs							
Millington, Tenn. Bldgs. 435-440	208/120	1.40	147/110	300	a	a	a
Pensacola, Fla. Bldgs. 3468-3475	208/120	2.3	288/132	c	24.0	5000[b]/0	200
Point Mugu, Calif. Bldgs. 241	208/120	0.3	29/22	c	a	a	a
Hospitals							
Millington, Tenn. Bldgs. 100	480/277	7.30	793[b]/450	1200	40	6000[b]/2000	d
Pensacola, Fla.	480/277	14.0	1360/921	c	61	6400[b]/3000	d
UOPHs							
Millington, Tenn. Bldgs. 599	208/120	1.00	183[b]/50	300	0.4	400/0	e
Pensacola, Fla. Bldgs. 3252	208/120	1.00	240[b]/40	c	0.5	500[f]/0	

[a]No meters.

[b]Peak occurs during summer months.

[c]Not available.

[d]Included in space heating data.

[e]Included in the gas consumption of an attached mess hall.

[f]Estimate based on engineering calculations by Hartkampf/Powell, Inc.

The UOPHs are considerably smaller than the UEPHs in both the number of people housed and the square footage of floor area. Their minimum electric usage is approximately 50,000 kWh per month. At Pensacola, the usage is 150 kWh per person per month. At Millington, the minimum usage per person is significantly larger since a dining facility is included in the electric energy usage. The peak monthly usage is relatively large, 183,000 kWh at Millington and 240,000 kWh at Pensacola. These are both cooling season peaks resulting from the use of the centrifugal chillers. These buildings also have peak demands in the range of 300 kW.

3.2.2 Space conditioning energy

The space heating and space cooling energy use data were not as complete as the electric energy usage data. For example, there were no steam meters for the UEPHs at Millington and no gas meters for the UEPH at Point Mugu. The only barracks for which monthly space heating energy use data were available are the UOPH at Millington and the UEPH at Pensacola.

Monthly gas data were available for the hospitals at Millington and Pensacola. Gas consumption data for the hopital at Millington were especially good. Four years of monthly gas consumption data were available. The results on Table 3.2 are based on these monthly data. In addition, daily gas and steam consumption data were available for 1982. The ratio of the steam-to-gas data implies an 80% boiler efficiency. In addition, these daily data showed that there were few days in a year when the steam consumption was less than 50,000 pounds (about 50 x 10^6 Btu/d). This is about 75% of the minimum month's steam consumption rate and will be used for sizing the cogeneration module for the hospital at Millington. Daily and hourly steam or gas data were not available for the Pensacola hospital. With the minimum month's steam consumption at Pensacola's hospital (Table 3.2) and the 75% found at Millington's hospital, the minimum daily steam consumption at Pensacola's hospital can be estimated to be 75,000 pounds (about

75 x 10^6 Btu/day). The minimum daily steam consumption estimates will be used in Sect. 4.

In the late 1970s, the U.S. Army Corps of Engineers monitored fuel use in 114 buildings on three Army posts.[9] Two building types, barracks and medical/dental facilities, were monitored. Regression analysis parameters for nonmodular barracks built after 1966 and medical/dental buildings are listed on Table 3.3. The coefficients indicate that the heating energy use per square foot of the floor area is about four times as large in hospitals as in barracks. The study did not distinguish between enlisted personnel housing and officer housing. The lines on Fig. 3.4 are the lines of the equations on Table 3.3. The equations on Table 3.3 and the lines on Fig. 3.4 are based on three medical/dental buildings and on two enlisted men's barracks plus an officers' barrack.[9,10]

The slope of the regression equation for the barracks (Table 3.3) is 7.4 Btu/ft^2-d-HDD. Metered gas data at the Millington UOPH (Building 599) fit a line with a slope of 7.0 Btu/ft^2-d-HDD. An independent engineering estimate for the Pensacola UEPH (Buildings 3468-3475) by Hartrampf/Powell, Inc., gave a slope of 8.5 Btu/ft^2-d-HDD. With this support, it appears that a heat-use slope of 7 to 8 Btu/ft^2-d-HDD can be expected for most modern nonmodular barracks.

Reference 9 gives a minimum daily fuel consumption of about 82 Btu/ft^2 for barracks. About the only use for this energy is heating domestic hot water which is used in barracks for bathing and for washing clothes. Consequently, it is expected that the base load depends more on the number of building occupants than the floor area of the buildings. As pointed out in Section 3.1.2, a UOPH usually has 2 to 3 times as much floor area per person as a UEPH; therefore, UOPHs are expected to have smaller minimum daily heat consumptions than UEPHs.

The curve developed by the Corps of Engineers for medical/dental facilities was assumed to be appropriate for Navy hospitals. The

Table 3.3. Heating energy consumption from U.S. Army Corps of Engineers study

General Linear Equation

$$E_h = a + b \times HDD_d ,$$

where E_h = daily heating fuel consumption (Btu/ft^2/d),

HDD_d = daily heating degree-days, and

a,b = regression parameter.

Barracks (modern nonmodular)

$$E_h = 81.91 + 7.4 \times HDD_d \text{ (Btu/ft}^2\text{/d)}.$$

Hospitals (medical/dental buildings)

$$E_h = 254.4 + 24.31 \times HDD_d \text{ (Btu/ft}^2\text{/d)}.$$

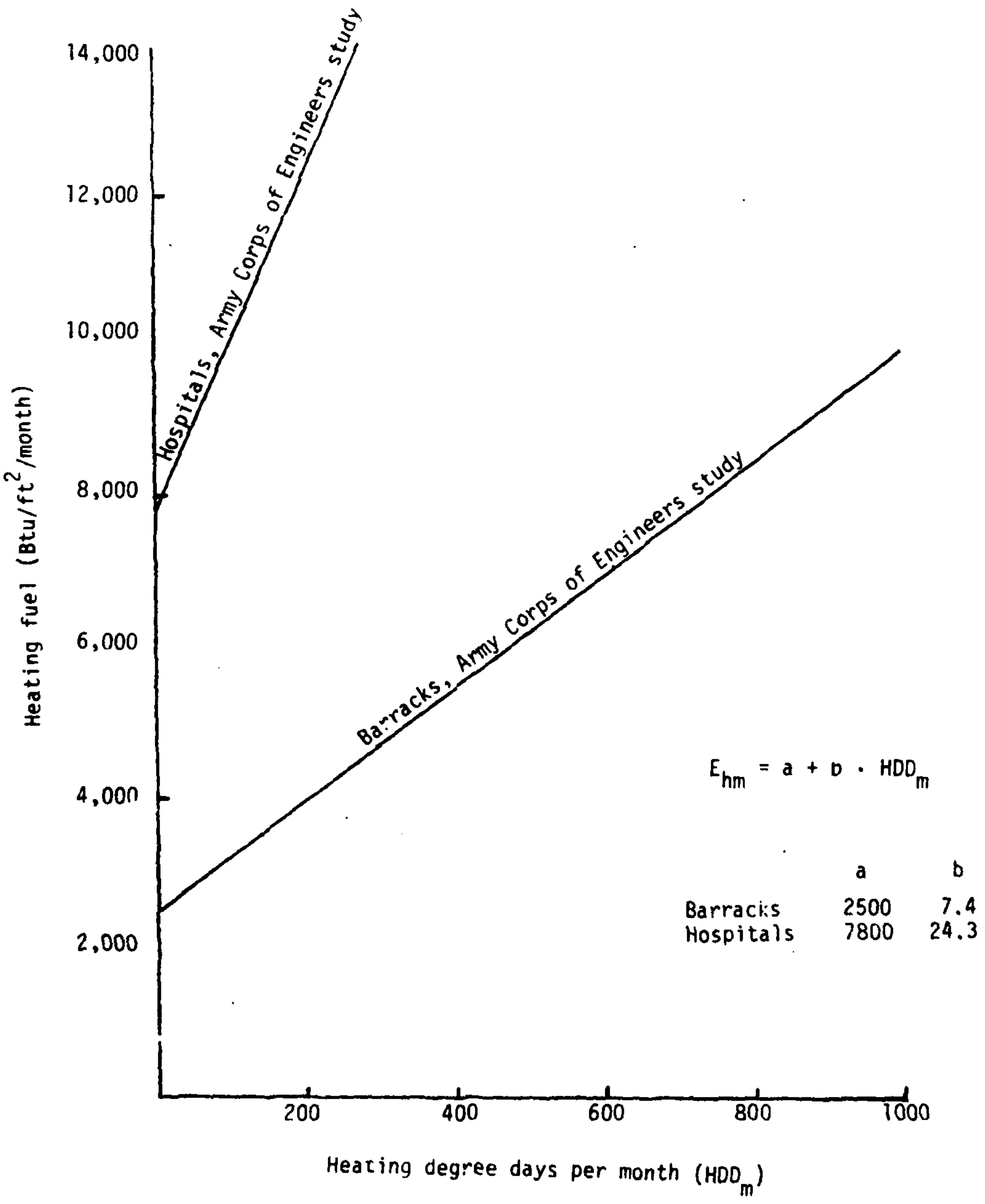


Fig. 3.4. Heating fuel loads.

regression equation for hospitals (medical/dental facilities) is also plotted in Fig. 3.4. Monthly weather data for each of the four Navy shore facilities are presented in Table 3.4.

3.2.3 Domestic hot water usage

Domestic hot water (DHW) energy consumption is particularly important for decentralized small cogeneration applications. While space heating and space cooling energy consumption varies considerably throughout a year, DHW usage is fairly constant from month to month. Unfortunately, there were no domestic hot water usage data available from the Navy bases visited during this study.

The steam used by the Pensacola UEPH, Buildings 3468-3475, heats the complex in winter, cools it in summer, and heats domestic hot water all year around. The DHW energy consumption estimate on Table 3.2 is the second lowest monthly steam usage for the years 1980, 1981, and 1982. (The lowest monthly steam usage was thought to be a data error.) No other data from the UOPHs or UEPHs of this study could be used to estimate DHW energy usage. The low values of monthly gas usage for the hospitals (Table 3.2) include DHW heating but also include process heat loads such as sterilization and, perhaps, some cooking.

One method for estimating domestic hot water energy usage in barracks is based on the Corps of Engineers study[9]. The intercept of the barracks curve (82 Btu/ft^2-d) can be interpreted as the average DHW fuel usage rate. Assuming a 60% water heating efficiency, the average DHW energy consumption rate of the Pensacola UEPH would be 360 x 10^6 Btu/month. This is considerably larger than the 200 x 10^6 Btu/month found from metered data (Table 3.2). If the 82 Btu/ft^2-d and 70% efficiency are used for the Pensacola UOPH, the DHW energy usage would be about 170 x 10^6 Btu/month or about one-third of the estimated maximum monthly space heating load (Table 3.2). Section 3.2.2 shows that the slopes of the regression equations from ref. 9 for barracks are consistent with data from Navy buildings but the intercept seems too large.

Table 3.4 Monthly weather data

Navy shore facilities	Monthly heating degree-days												
	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sept.	Oct.	Nov.	Dec.	Yearly total
Millington, TN	729	585	456	147	22	0	0	0	18	130	447	698	3232
Pensacola, FL	400	227	183	36	0	0	0	0	0	19	195	353	1463
Groton, CT	1097	991	871	543	245	45	0	12	87	347	648	1011	5897
Point Mugu, CA	372	302	288	219	158	81	28	28	42	78	180	291	2061

Another source of information on domestic hot water use comes from a steam-monitoring study by Messock of the Navy Energy and Environmental Support Activity.[11] Messock measured several days of summertime hourly steam consumption of a UEPH (Bldg. 3342) at Cherry Point, N.C. An average DHW steam consumption of 2928 lbs per day was measured for this 250-person barrack. This gives an average of about 11.7 lb of steam per person per day. Assuming an 80% steam-to-hot water heating efficiency, 10,400 Btu of heated water is consumed per person per day. This is equivalent to about 3.2×10^5 Btu of heated water per person per month. By way of comparison, the DHW energy consumption for the Pensacola UEPH is 5.2×10^5 Btu/person-month, based on Table 3.2. These estimates span a wide range approximately centered on Messock's value. Messock's value is probably the best estimate since it was the only estimate which is based on measurements of energy used for domestic water heating. For the purposes of the next section, the 10,400 Btu/person-d average DHW energy consumption found by Messock will be used for the barracks.

The time of DHW usage is also important for decentraled small cogeneration applications. Messock's steam-monitoring study also measured the hourly variation of DHW energy consumption. Table 3.5 gives the hourly DHW data from ref. 11. The DHW heating energy consumption pattern between 1000 h on 6/13 and 1700 h on 6/16 is used to size thermal energy storage for cogeneration applications at UEPHs and UOPHs. The method is described in the next section. The principal feature to note in Table 3.5 is the pattern of DHW use. Virtually no DHW is used for several hours; then, in the period of an hour or two, a considerable quantity is used. This energy use pattern requires that thermal energy storage be used with cogeneration lest the cogeneration module waste a large fraction of its cogeneration heat or run a small fraction of the time.

No DHW energy use estimates were available for the hospitals. For the purposes of this study, the domestic hot water energy use was assumed to be half of the minimum monthly heat load. The remainder was

Table 3.5 Time variation of domestic water heating energy consumption*

UEPH (Building 3742) at Cherry Point, North Carolina, sverage steam consumption (lbs/h)							
Time	6/13 (Fri)	6/14 (Sat)	6/15 (Sun)	6/16 (Mon)	6/17 (Tue)	6/18 (Wed)	6/19 (Th)
0000	**	0	0	0	**	**	0
0100	**	0	0	0	**	**	**
0200	**	96	0	0	**	**	**
0300	**	550	0	0	**	**	**
0400	**	0	0	0	**	**	**
0500	**	0	0	0	**	**	**
0600	**	0	0	68	**	**	**
0700	**	0	270	960	**	**	**
0800	**	0	369	0	**	0	**
0900	**	28	0	0	**	0	**
1000	0	873	0	0	**	0	**
1100	0	0	0	0	**	0	**
1200	0	0	755	0	0	232	**
1300	0	282	0	0	0	387	**
1400	0	489	0	0	0	74	**
1500	0	0	0	0	0	488	**
1600	0	0	0	898	0	0	**
1700	353	0	457	0	825	430	**
1800	0	0	206	**	0	107	**
1900	121	462	0	**	0	0	**
2000	684	317	0	**	465	0	**
2100	0	0	0	**	615	0	**
2200	0	0	543	**	0	0	**
2300	0	0	158	**	0	617	**
Daily total	N/A	3097 lb	2758 lb	N/A	N/A	N/A	N/A
Average consumption	N/A	129 lb/h	115 lb/h	N/A	N/A	N/A	N/A

*Data are from a study by Messock of the Naval Energy and Environmental Support Activity.[11]

**No data for this hour because of instrumentation problems.

assumed to be used for purposes for which cogenerated hot water would not be suitable.

3.3 Energy Costs

The costs of fuel and electricity strongly affect the economic attractiveness of cogeneration. The fuel and electricity prices at the four bases cover a wide range.

The electricity prices charged to the four Navy Bases are summarized on Table 3.6. As can be seen, a variety of billing structures are in use. While Point Mugu has a three-tier price structure, the other bases buy electric power and energy at a single price. Demand charges range from a high of \$12/kW at Groton to no demand charge for off-peak power at Point Mugu. Millington has a very low electricity price. Groton and Pensacola pay close to the same price for electricity. Point Mugu has the highest electricity prices at 5.4¢/kWh for off-peak and 7.8¢/kWh for on-peak purchases.

Fuel prices are highest at Groton and Point Mugu (Table 3.7). Millington and Pensacola have relatively low natural gas prices. Both Millington and Point Mugu buy a combination of firm and interruptible gas; however, at Millington the price difference is small while at Point Mugu the price difference is about \$1.50 per 10^6 Btu.

The secondary fuels at Groton and Point Mugu are of interest. Since no small cogeneration module burns No. 6 oil and since natural gas is not available at Groton, a diesel burning cogeneration module would be required. Also, No. 2 oil (diesel) is much more expensive than the No. 6 oil used at the central power plant, which reduces the attractiveness of decentralized cogeneration.

At Point Mugu, the situation is nearly the opposite; the G-COG (footnote e, Table 3.7) gas rate makes most or all of the gas consumed for cogeneration available at a savings of between \$1.00 and \$2.50 per 10^6 Btu. This natural gas price structure substantially improves the economic attractiveness of cogeneration at Point Mugu.

Table 3.6. Electric billing schedule

Base	Demand charge, $/kW			Energy charge, ¢/kWh		
	On-peak	Mid-peak	Off-peak	On-peak	Mid-peak	Off-peak
Groton, CT[a]	N/A	N/A	12.00	N/A	N/A	3.8517
Millington, TN[b]	N/A	N/A	6.70	N/A	N/A	2.574
Pensacola, FL[c]	N/A	N/A	6.25	N/A	N/A	3.64
Point Mugu, CA[d]	5.05	0.65	0.00	7.821	6.517	5.431

[a]Prices current as of March 1983.

[b]Prices current as of October 1982.

[c]Prices current as of January 21, 1983.

[d]Prices current as of June 1983. Time periods are defined as follows:

On-Peak: 1:00 p.m. to 7:00 p.m., summer weekdays except holidays
5:00 p.m. to 10:00 p.m., winter weekdays except holidays

Mid-Peak: 9:00 a.m. to 1:00 p.m. and 7:00 p.m. to 11:00 p.m., summer weekdays except holidays
8:00 a.m. to 5:00 p.m., winter weekdays except holidays

Off-Peak: All other hours

Off-peak holidays are New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas.

When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change in off-peak will be made for holidays falling on Saturday.

The summer season shall commence at 12:01 a.m. on the last Sunday in April and continue until 12:01 a.m. of the last Sunday in October of each year. The winter season shall commence at 12:01 a.m. on the last Sunday in October of each year and continue until 12:01 a.m. of the last Sunday in April of the following year.

Table 3.7 Navy Shore Base Fuels Charges

Base	Principal fuel			Secondary fuel	
	Fuel type	Service priority	Commodity charge ($\$10^6$ Btu)	Fuel type	Commodity charge ($\$/10^6$ Btu)
Groton, Conn.[a]	No. 6 oil	N/A	6.1486	No. 2 oil	8.7050
Millington, Tenn.[b]	natural gas	firm/interruptible	3.50/3.16	No. 2 oil	9.86
Pensacola, Fla.[c]	natural gas	firm	3.67	N/A	—
Point Mugu, Calif.[d]	natural gas	firm/interruptible	7.1810/5.6746	natural gas[e]	4.604[e]

[a]Fuel prices current as of March 1983.

[b]Fuel prices current as of October 1982. Firm (G-9) and interruptable (G-10) gases are metered separately.

[c]Fuel prices current as of February 1983.

[d]Fuel prices current as of June 1983. All gas is purchased through a single meter; 67% of purchased gas is firm (GN-2) and the remainder is interruptable (GN-3).

[e]This rate (G-COG) is available to qualified cogenerators for up to 0.118 x E therms, where E is the electricity (kWh) produced by the cogeneration during the billing period. Additional gas is billed at the regular rate. This price is valid until October 1983.

4. SELECTION OF COGENERATION EQUIPMENT

Virtually any of the cogeneration modules described in Sect. 2 could be used with any of the applications described in Sect. 3. However, some modules will perform better than others in particular applications. For instance, an excessively large cogeneration module will either run few full-load hours or waste much of the cogenerated heat. This section discusses the considerations which are important in matching cogeneration equipment to particular buildings, the selected equipment-building matches, and the energy characteristics of the selected cogeneration applications.

4.1 General Considerations

Cogeneration is of interest primarily because it is an energy-conserving technology. Electricity and useful heat can be cogenerated while using less fuel than is required for separate generation. The principal problem in cogeneration is designing applications which have a sufficiently high return-on-investment that investors will find it attractive.

Like many energy conservation technologies, cogeneration requires an initial capital investment which pays for itself by saving energy. The costs of electricity and fuel are critically important. If the price of electricity is too low relative to the price of fuel, operation of cogeneration equipment may lose money while it saves energy. Even if the relative prices of electricity and fuel are such that operation of cogeneration equipment saves money, their absolute prices may be so low that it takes an unreasonable time to pay off the investment.

The other side of the issue is the cost of the cogeneration equipment. Of two cogeneration applications, each of which saves the same amount of money, the one which has the lowest first cost will be the most attractive investment. The amount of time cogeneration equipment operates is also important. If two cogeneration applications save the same amount of money in each hour of operation, the application which has the largest number of annual hours of operation will be the most attractive investment.

Cogeneration means simultaneous production of two useful energy products; however, all the energy that is produced may not get used. In the total energy applications discussed in Sect. 1, it was sometimes necessary to run cogeneration equipment to produce electricity even when there was no need for the cogenerated heat. Since the applications being examined here do not require stand-alone electric generation, this should not be necessary. In any case, the most profitable operation will occur when both the electricity and cogenerated heat are put to use. Also, the applications described below will show that operating these cogeneration modules for electricity without using the cogenerated heat is a money-losing situation.

In order for a cogeneration module to give good service, it must be reliable and easily maintained. All the cogeneration modules described in Sect. 2 should be easily maintained since they use conventional technologies and all but Martin offer service contracts. While a maintenance contract can protect the Navy from unexpected repair costs, a maintenance contract does not protect against the costs of loss of service. A cogeneration module which is out of service because of breakdowns is not saving the Navy any money on its energy bills.

The modules described in Sect. 2 are designed for automatic operation. Automatic controls to turn the module on and off are part of the installation. Some of the total energy systems discussed in Sect. 1 require an operator to attend the TE system. The earnings of the small cogeneration systems being examined here are too small to support an operator. We have assumed that local regulations do not require an operator for these decentralized small cogeneration applications.

On-site generation of electricity causes problems for electrical utilities. There are safety concerns about having generating capacity at the ends of distribution lines. There is concern for the synchronization of the on-site-generated power with the utility-generated power. There are billing complexities associated with selling electricity back to utilities. In order to avoid complicated technical or contractual arrangements, these problems must be either solved or avoided.

The complexities involved with selling electricity back to utilities is easily avoided by selling none back. The easiest way to ensure this is to install less on-site-generated capacity than the minimum electricity needs of the Navy shore facility. If more on-site generating capacity is installed, then care must be taken to ensure that no excess is generated, or the base will have to enter into these complex contractural arrangements. We assume in our analysis that the installed on-site generating capacity is kept far below the minimum facility needs.

The safety and synchronization problems can be handled in either of two ways. Use of induction generators solves both of these problems because induction generators must be excited by the power on the utility line. Consequently, if the utility power line is operating, then the induction generation operates in synchrony with the utility power, but if the power line is down, the induction generator cannot operate.

A synchronous generator is self-exciting but has the advantage that it can be used to produce emergency power if the utility line fails. However, if synchronous generators are used, they must have controls which automatically keep them synchronized with the utility power and they must be provided with automatic isolation devices which isolate the synchronous generator and the load to be served from the utility power line if the utility power line fails.

In a building where additional emergency back-up power is required, it may be that the extra costs of a synchronous generator cogeneration module could be partially or wholly offset by the avoided costs of a standby generator set. On the other hand, in buildings like hospitals with a critical need for reliable back-up power, a cogeneration module which will be out of service at least 4-8 h per month for preventive maintenance may not meet statutory requirements. Since none of the buildings studied here have an established need for additional emergency back-up power, induction generators are assumed in every case.

4.2 Cogeneration Module Size Selection

The most attractive small cogeneration applications will be those with large returns-on-investment. As discussed above, a large return-on-investment is achieved by minimizing the initial cost of the cogeneration equipment while maximizing the annual savings of the equipment. Maximum annual savings is achieved by operating the cogeneration module full time while using all of the cogenerated heat and electricity.

In order to allow the cogeneration module to run as close as possible to full time while using all the cogenerated heat, modules were selected which cogenerated heat at a rate nearly equal to the minimum daily average building heat consumption. In practice, this heat production rate is the average domestic hot water (DHW) energy use rate.

An alternative which was considered but rejected was to meet parts of the space heating and cooling loads as well as the DHW loads with cogenerated heat. This leads to the selection of larger cogeneration modules, but it also leads to the addition of absorption chillers for space cooling and a more complex installation. Absorption chillers designed to be compatible with the approximately 200°F cogenerated heat significantly increase the cost of a cogeneration system yet are used less than half the year. Since it was judged that meeting space heating and cooling loads would not increase the rate or return-on-investment over DHW heating alone, cogeneration modules were sized to meet the DHW load. (In a few cases where the average DHW load was smaller than the heat ouput rate of the smallest cogeneration module, part of the space heating load was assumed to be met by the cogeneration module.)

4.3 Thermal Energy Storage Sizing

As shown by Fig. 3.5 domestic hot water usage in barracks is very unsteady. A cogeneration module sized for the average DHW load will almost always produce more or less heat than needed in a particular hour. Thermal energy storage acts as a buffer between a module's steady heat output and an unsteady DHW load.

Proper thermal energy storage (TES) sizing is important. An excessively large TES system will seldom or never be filled and thus constitutes an incompletely used investment. A too small TES system will be full before enough heat is stored to meet the next period of demand for domestic hot water; consequently, the cogeneration module will be underused.

The proper TES size can be expected to depend on the heat production rate of the module, the average heat consumption rate of the load, and the variation of that load. Although the cogeneration module sizing goal described in Sect. 4.2 is for the heat production rate to equal the minimum average heat consumption rate, the discrete sizes in which cogeneration modules are made makes this only approximately achievable.

In order to select the proper TES capacity for any particular combination of average DHW load and cogeneration module heat production rate, a simple Fortran computer program was written based on the DHW load pattern on Fig. 3.5 between 1000 hours, June 13, and 1700 hours, June 16 (Appendix A). Figure 4.1 shows that beyond a certain point, additional TES capacity serves no purpose. For example, if the cogeneration modules heat production rate is half of the average DHW energy consumption rate, then each hour of additional heat storage up to 5 h increases the fraction of the DHW load supplied by cogeneration, but beyond 5 h, additional storage does not increase the use of cogenerated heat. This is because additional storage cannot make the cogeneration module produce heat at more than half the average heat consumption rate.

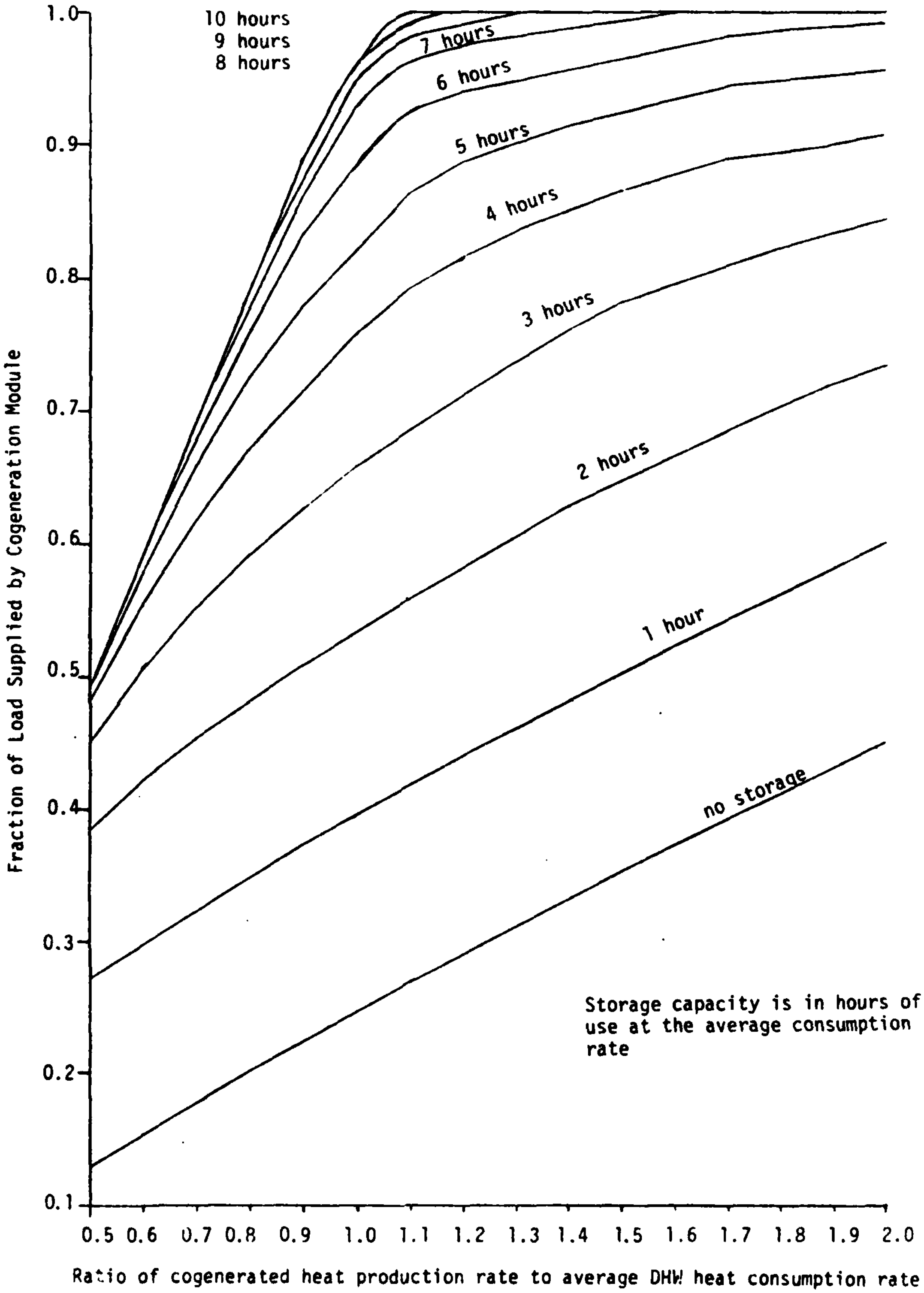


Fig. 4.1. Fraction of DHW load met by cogeneration.

Where the heat production rate is much larger than the heat consumption rate, TES capacity beyond a certain point has no value because it is never emptied. For example, if the heat production rate is twice the average heat consumption rate, Fig. 4.1 shows that not much more than 6 h of heat storage is useful.

The largest useful heat storage capacity occurs where the heat production rate nearly equals the average DHW heat consumption rate; up to about 8 h of storage is useful. The 8 h of storage corresponds to the approximately 8 h between DHW use shown in Fig. 3.5. These results are entirely dependent on the nature of the load. Insofar as the data on Fig. 3.5 is representative of DHW usage in barracks, Fig. 4.1 shows the relationship between the fraction of the DHW load provided and the TES heat storage capacity.

Since Messock's data (Fig. 3.5) are the only hourly barrack DHW data available for this study, Fig. 4.1 was used to size the heat storage tank. As discussed in Sect. 2.3, the tanks assumed for this study are available in increments of 1000 gal up to 10,000 gal. Tanks with volumes of 1500 and 2500 gal are also available. We have assumed that the storage temperature is 100°F hotter than the potable water supply temperature. This assumption gives heat storage capacities of about 830,000 Btu/1000 gal of volume.

Figure 4.2 shows the fraction of the time that a cogeneration module must run to provide the fraction of the load shown in Fig. 4.1. This is also based on Messock's data and the computer program listed in Appendix A.

For the barracks, the thermal energy storage sizing procedure involved three steps. The first step was to determine the ratio of the heat production rate to the average DHW heat consumption rate. Figure 4.1 was then used to determine the appropriate number of hours of TES to use. The standard tank size with the heat storage capacity closest to, but not much less than the desired capacity was selected. After the TES capacity was selected, Fig. 4.1 was used to determine how much heat was provided by the cogeneration module. Figure 4.2 was then

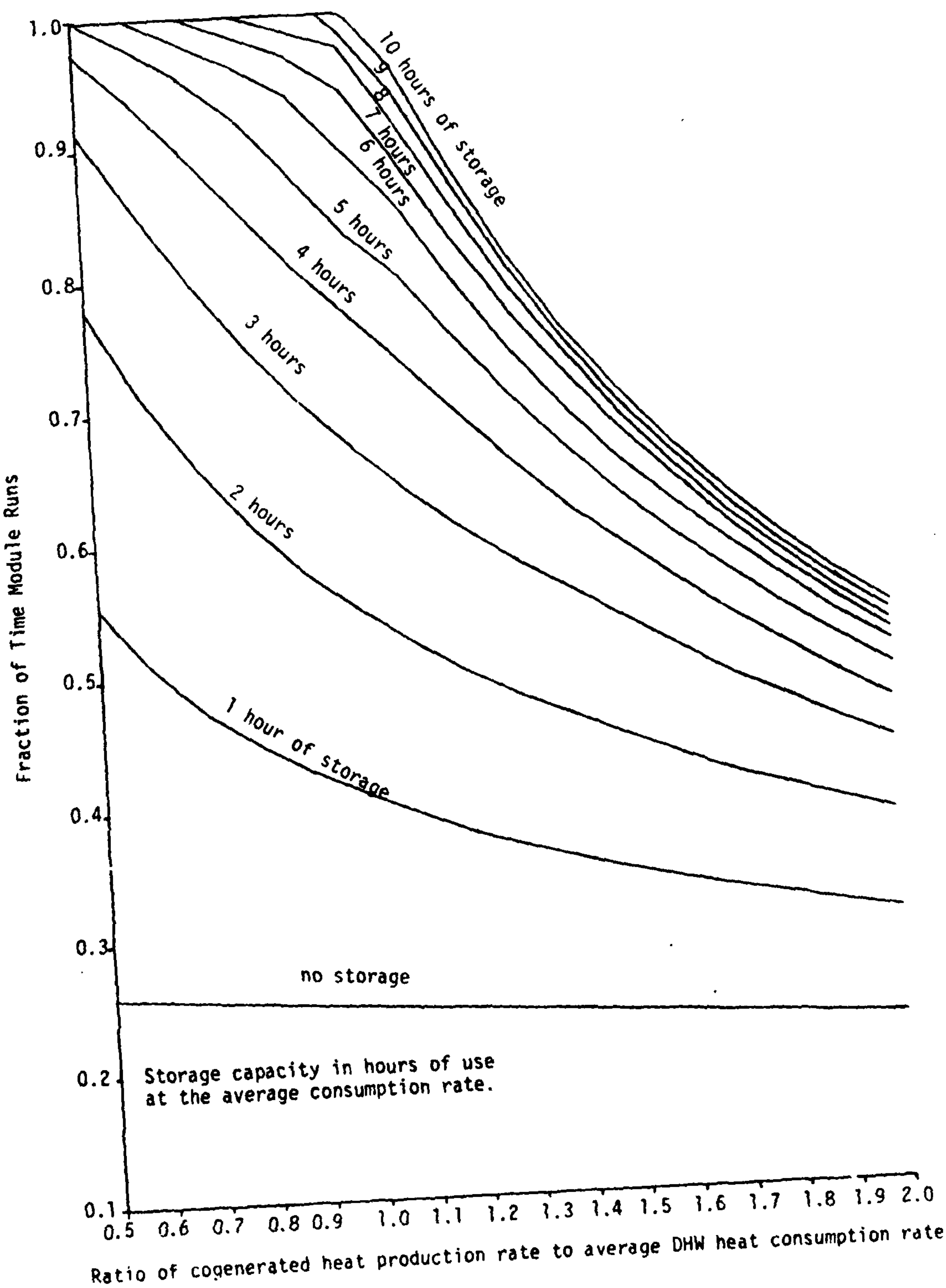


Fig. 4.2. Fraction of time the cogeneration module runs.

to determine the amount of time the cogeneration module operates. The example in Sect. 4.4 illustrates the procedure.

Hospitals have hot water energy consumption patterns much different from those of barracks. Unfortunately, no hourly hot water energy consumption data were available. Consequently, two assumptions were made. The first was that half the minimum monthly heat consumption (Table 3.1-b) could be provided by cogenerated heat below 200°F. The second was that the heat consumption of a hospital was more steady than that of a barrack, so 2 h of heat storage of the heat production rate was sufficient. This second assumption is used to size TES for the hospitals.

4.4 Cogeneration Systems Characteristics

Table 4.1 gives the characteristics of the cogeneration systems selected for each building. Before comparing the systems, it is helpful to go through the steps involved in selecting the cogeneration systems. For example, for the UEPH at Point Mugu, the WESI module VRG 220/30 was selected.

The module was selected because its heating capacity was close to the 164 x 10^3 Btu/h minimum average heat load of the building (Table 2.2). The smaller WESI module, VRG 155/15, would have matched the load nearly as well but there would have been little savings on capital cost (Table 2.3).

The ratio of the VRG 220/30 heat output rate to the average load is 1.16. Figure 4.1 shows that up to 9 h of heat storage is beneficial. This requires about 1800 gal; 2000 gal would provide excessive storage. In fact, it would cause the module to operate more without meeting more, of the load (Figs. 4.2 and 4.1 for 10 h of storage.) The next standard size is 1500 gal. It provides about 7.6 h of storage. Figure 4.1 shows that 7.6 h of storage would provide about 98% of the DHW load. Figure 4.2 shows that the module will run about 87% of the time.

Table 4.1 Cogeneration systems characteristics

Application site	Minimum average heat load (10^3 Btu/h)	Selected modules	Heat output rate (10^6 Btu/h)	TES capacity* (10^6 Btu/gal)	Fraction of DHW load provided (%)	Fraction of time module runs (%)
Hospital						
Pensacola	1563	F1905G/175 F1197G/105	1570	3.3/4000	99	39
		3-Thermo Electron	1320	3.3/4000	84	99
Millington	1042	F1905G/175	938	2.1/2500	89	99
		2-Thermo Electron	880	2.1/2500	85	99
UEPH						
Pensacola	501	Thermo Electron	440	4.1/5000	86	99
Millington	264	VRG 330/45	270	2.1/2500	99	97
Groton	258	DWI-120	765	0.8/1000	100**	77
Point Mugu	164	VRG 220/30	190	1.2/1500	98	87
UOPH						
Pensacola	112	VRG 155/15	131	0.8/1000	98	85
Millington	37	VRG 155/15	131	0.13/160	100**	64

*Assumes heat is stored for consumptive hot water use, e.g., DHW.
**Because the smallest module is so large some of the space heating load is assumed to be met.

The hospitals are the largest applications, and the WESI F1905G/175 matches the Millington hospital load rather closely. Operating 99% of the time, it provides 89% of the load. Inspection of Table 4.1 shows that no module operates more than 99% of the time. This is because we have assumed that the modules are serviced for an average of about 8 h per month.

The combination of the two WESI modules matches the thermal load of the Pensacola hospital extremely closely. The modules operate 99% of the time and together provide 99% of the load. The two WESI modules produce about as much as either the Martin cogeneration module G379 NA-HCR or G379 SCAN-LCR. However, the two WESI modules together cost much less than either of the G379 modules (Table 2.1). If a need for additional standby power existed at Pensacola, the extra cost of one of the Martin or Cogenic modules might have been justified. For a new hospital; synchronous cogeneration equipment may be justified if some or all of the emergency generators could be avoided thereby.

Because Thermo Electron modules recover more heat per unit of fuel than the other modules, combinations of two and three modules were tried for hospital applications. Because the Thermal Electron module is available in only one size, it was not possible to match the cogeneration system's heat output to the heat load as closely as with the variety of ESI modules. Table 4.1 shows that, as a result of using Thermo Electorn modules, a smaller fraction of the heat load is provided by cogeneration than with WESI modules.

The UEPH applications at Pensacola and Millington are similar to but larger than the application at Point Mugu. The UEPH application at Groton is quite different from the others. The notable thing about this application is the very large size of the module compared to the load. As discussed in Sect. 4.2, this is not a good match between module and load but Cogenic's DWI-120 was selected because it was the smallest diesel fuel module available. Some extrapolation was required to size the thermal energy storage for this application since Figs. 4.1 and 4.2 do not extend to output-to-load ratios of three. If this module were used to meet the DHW load only, like most of the applications, the module would run about 34% of the time. Since this kind of operation is sure to be economically unattractive, we assumed that, during 8 months of the year, the module runs 99% of the time meeting part of the space heating load. The UOPH application at Millinton is a similar situation since the VRG 155/15 is the smallest cogeneration module made.

Table 4.2 lists operation characteristics of the cogeneration applications. The number of annual hours of operation is the product of 8760 h/year and the fractional run time from Table 4.1, or 8664 h/year (8760-96) whichever is less. The fuel consumed, the electricity produced; and the heat produced are the products of the annual hours of operation and the module energy characteristics from Table 2.2. In most cases, the credited electricity capacity is the electric generating capacity of the module. The capacity credits of the Groton UEPH and the Millington UOPH are reduced because the module operates substantially less than full time. Notable features of Table 4.2 are the differences in energy productions and consumptions. The fact that hospitals use large quantities of energy and the UOPHs use relatively little is reflected in the energy magnitudes on Table 4.2.

The net energy savings given on Table 4.2 are based on the energy quantities on Table 4.2 and two assumptions. For the purposes of this study, electricity is assumed to be supplied at a heat rate of 11,600 Btu/kWh; this factor is used to convert kilowatt hours to equivalent Btu. The second assumption is on the efficiency of delivering heat by the conventional method. If a gas-fired boiler is used, then 80% efficiency is assumed. If a steam district heating system is used, then 72% efficiency is assumed.

The net energy savings for the two hospitals show that there is a significant difference in the operation of the WESI and Thermo Eectron cogeneration modules. At Millinton's hospital, the net energy savings are nearly the same whether one 175-kW WESI module is used or two 60-kW Thermo Electron modules are used. This occurs because the WESI module produces nearly 50% more electricity while burning nearly 50% more fuel

Table 4.2 Annual operating characteristics

Application site	Hours of operation	Fuel consumption (10^6 Btu/year)	Credited electric capacity (kW)	Electricity produced (MWh/year)	Heat produced and used (10^6 Btu/year)	Net energy savings* (10^6 Btu/year)
Hospital						
Pensacola						
WESI	8,664	31,537	280	2,426	13,602	13,607
Thermo Electron	8,684	20,149	180	1,560	11,436	12,242
Millington						
WESI	8,664	19,841	175	1,516	8,127	7,903
Thermo Electron	8,664	13,433	120	1,040	7,624	8,161
UEPH						
Pensacola	8,664	6,716	60	520	3,872	4,694
Millington	8,497	5,098	45	382	2,294	2,519
Groton	6,745	9,001	93	809	5,160	7,550
Point Mugu	7,621	3,201	30	229	1,408	1,215
UOPH						
Pensacola	7,446	2,159	15	112	975	494
Millington	5,563	1,613	8	83	729	261

*Assumes that conventionally generated electricity requires 11,600 Btu/kWh.[10] Also, more energy is saved than heat is produced by cogeneration because of the inefficiencies of boilers and heat exchangers.

than the Thermo Electron modules. The difference is apparently in the efficiency with which the modules recover cogenerated heat. The smaller Thermo Electron module cogenerates more heat per unit of fuel consumed than do the WESI modules. This comparison shows that, when energy savings are of concern, the efficiency with which heat is recovered may be as important as the electric generating efficiency. (The heat recovery characteristics of the WESI cogeneration modules used herein are preproduction estimates and may not correspond to the actual production characteristics.)

5. ECONOMIC ASSESSMENT

5.1 Economic Parameters

An investment can be characterized in many ways. Three economic characteristics which are commonly used are simple payback period, net present worth (NPW), and savings-to-investment ratio (SIR). A fourth parameter, the energy savings-to-investment ratio (E/C), is used by the military services in evaluating energy conservation investments. Capital cost is always of concern in relation to the earnings or savings which can result. The size of a capital investment is of concern by itself. Since funds are generally in short supply, large capital projects receive closer scrutiny than smaller projects. Small projects are sometimes approved by lower levels of management than are large projects.

The first-year annual net savings are easily estimated with good accuracy. Successive years' savings can be estimated with less confidence because energy prices, building energy needs, and cogeneration equipment performance are more uncertain. The simple payback period is the length of time it takes for the savings to pay for the capital investment. While more sophisticated measures of return-on-investment are available, simple payback period is easily understood and gives a sense of how long conditions need to remain stable to break even.

The net present worth (NPW) of a project is the present value of the sum of the earnings less the costs* over the life of the project. For this assessment, the project life is assumed to be 15 years, though there is no technical reason that the project life cannot be longer. The present value is based on a 7%/year discount rate.

The dollar savings-to-investment ratio (SIR) and the energy savings-to-investment ratio (E/C) are parameters of special interest

*Maintenance costs were assumed to include the costs of repair and replacment during the 15-year project life.

to the Navy. The SIR is the ratio of the discounted present value of the net operating savings (or earnings) over the project life to the capital cost of the investment. A project with an SIR greater than 1.0 is considered cost beneficial to the Navy. The E/C is the ratio of the first year's net energy savings to the capital cost of an energy conservation investment. Both E/C and SIR are used by the Navy to select amongst energy conservation projects.

5.2 Economic Analysis

The annual savings from operating a cogeneration module equals the values of the heat produced, the electricity produced and credits for avoided capacity charges, less the costs of fuel and maintenance. The worth of cogenerated heat is equal to the cost of the fuel presently used to produce the heat divided by the efficiency of production and delivery of that heat as described in Sect. 3. For example, if the central steam plant burns \$4.80/million Btu natural gas in an 80% efficient boiler and 75% of steam heat sent out is delivered to the load at the heat exchanger, then the heat produced by the cogeneration module is worth \$8/million Btu [\$4.80/(0.8 x 0.75)]. With no sale of cogenerated electricity, the value of electricity produced and the credit for avoided capacity charges are equal to those charged to the base by the local utility. The electricity and fuel prices for four bases are listed on Tables 3.6 and 3.7. Table 5.1 lists the first year cogeneration earnings and expenditures for each of the applications computed from Tables 3.6, 3.7, and 4.2.

The importance of electricity prices is illustrated by comparing the earnings of the applications (Table 5.1) at Pensacola and Millington. For instance, the hospital application at Pensacola (WESI module) produces 60% more electricity than the one at Millington (WESI module) (Table 4.2), but the electricity produced at the Pensacola hospital is worth twice as much as that produced at the Millington

Table 5.1 First-year cogeneration earnings and expenditures, constant dollars

Application site	Operation and maintenance	Cost of fuel consumed	Value of heat produced*	Value of electricity produced	Electrical capacity credits	Net cogeneration earnings
Hospital						
Pensacola						
WESI	29,300	115,700	62,400	88,300	21,000	26,700
Thermo Electron	23,400	74,000	52,500	56,800	13,500	25,400
Millington						
WESI	15,200	69,400	35,600	39,000	14,100	4,100
Thermo Electron	15,600	47,000	33,400	26,800	9,600	7,200
UEPH						
Pensacola	7,800	24,600	19,400	18,900	4,500	10,400
Millington	3,800	17,800	11,200	9,800	3,600	3,000
Groton	16,200	78,300	44,100	31,200	13,400	-5,800
Point Mugu	3,400	15,800	11,800	14,100	2,000	8,700
UOPH						
Pensacola	1,100	7,900	5,000	4,100	1,100	1,200
Millington	800	5,600	3,200	2,100	600	-500

*Includes corrections for fuel-to-heat conversion efficiencies.

hospital. This is a reflection of the different electricity prices at the two bases (Table 3.6). The very low price of electricity at Millington is the reason the net cogeneration earnings are so low at Millington. Comparing the UEPHs and UOPHs at Pensacola and Millington shows similar effects from the electricity prices.

The UEPHs on Table 5.1 show other fuel price effects. Most striking is Groton, which loses money by operating. The reasons for this are that the module uses expensive No. 2 oil and displaces substantially less expensive No. 6 oil burned at the central power plant and that the diesel fuel-burning module costs \$0.02/kWh for maintenance. At the other end of the spectrum, the relatively small (30-kW) module at Point Mugu has net earnings which are relatively high. This occurs because electricity prices at Point Mugu are quite high (Table 3.6) and because natural gas used for cogeneration is considerably less expensive than the gas used for other uses (Table 3.7). The economic climate for cogeneration at Point Mugu is unusually favorable.

Comparison of the earnings of the WESI and Thermo Electron systems at the hospitals again shows the value of recovering a large fraction of cogenerated heat. At both hospitals, the net cogeneration earnings are close to the same whether the WESI or Thermo Electron modules are used, but the fuel consumed and electricity produced are quite different. The relatively higher earnings of the smaller Thermo Electron module systems are due to their relatively greater heat recovery efficiency. Also, as Table 5.1 shows, their relatively higher earnings are in spite of higher maintenance costs (1.5¢/kWh vs 1.0¢/kWh).

Table 5.2 lists the economic characteristics of the applications. The capital costs were estimated using the equipment cost data (Table 2.3), extra costs for lower voltage generators and switchgear (Table 2.6), thermal energy storage cost estimates (Section 2.3), and installation cost estimates. The savings-to-investment ratio and the net present worth were estimated using uniform present worth (UPW) discount factors required for energy conservation investments in the

Table 5.2 Economic characteristics

Application site	Capital cost ($)	First-year savings ($)	Simple payback period (year)	Savings-to-investment ratio*	Net present worth ($)*	Annual energy savings-to-investment ratio (10^3 Btu/$)
Hospital						
Pensacola, Fla.						
WESI	186,000	26,700	33	1.1	21,100	73
Thermo Electron	142,200	25,400	5.6	2.0	143,800	86
Millington, Tenn.						
WESI	115,000	4,100	28	-0.1	-127,900	69
Thermo Electron	94,500	7,200	13	0.9	-13,500	86
UEPH						
Pensacola, Fla.	58,000	10,400	5.6	2.1	-65,100	81
Millington, Tenn.	44,000	3,000	15	-0.4	-19,300	57
Groton, Conn.	112,000	-5,800	—	1.1	14,300	67
Point Mugu, Calif.	36,000	8,700	4.1	2.6	55,900	34
UOPH						
Pensacola, Fla.	31,000	1,200	26	0.3	-22,900	16
Millington, Tenn.	36,000	-500	—	-0.3	-43,300	7

* Assuming a 15-year project life to the Department of Energy's fuel price escalation factors and a 7% discount factor.

U. S. Department of Defense.[10] These UPW factors are based on a 7% discount rate and Department of Energy projected energy price escalation rates. In each case, the project life was assumed to be 15 years.

The economically attractive applications are the hospital and UEPH at Pensacola, the UEPH at Groton, and the UEPH at Point Mugu. All the applications at Millington are unattractive because of the facility's very low electricity prices. The UEPH application at Groton is unattractive the first year, in part because of the excessively large and expensive diesel-fueled cogeneration module and, even more important, the No. 6 oil that is displaced is much less expensive than the No. 2 oil the module uses. It is attractive over the longer run because residual oil used by the steam plant is expected to increase in price faster than diesel fuel or oil. The UOPH at Pensacola is unattractive because of the high cost and low efficiency of the WESI 15-kW cogeneration module. Table 2.3 shows that it costs very little less than the 30-kW module, and Table 2.2 shows that it is less efficient than the 30-kW module. Table 5.2 shows the economic advantage of using a cogeneration module which recovers a larger fraction of cogenerated heat (see the hospitals on Table 5.2).

The applications are economically attractive because of two important factors. First, the fuel and electricity prices are conducive to cogeneration. Second, a reasonably priced and reasonably efficient cogeneration module which matches the heat load is available. Where natural gas or a reasonably priced substitute is not available, otherwise attractive small cogeneration applications may be unattractive.

5.3 Sensitivity Analysis

Table 5.2 of the preceeding section shows that there are attractive decentralized small cogeneration applications on Navy bases and indicates what characteristics make an application attraction. This section is a more general examination of the sensitivity of simple payback period (SPP) to the factors which affect economic attractiveness.

The first factor which affects economic attractiveness is the per-hour cogeneration earnings (CE, \$/h). This factor is the difference between the values of the heat and electricity produced and the costs of fuel and maintenance. From an economic attractiveness point of view it does not matter if heat is more valuable than electricity or the other way around as long as their combined value is sufficiently higher than the costs of fuel and maintenance. However, maintenance generally will cost 1-2¢/kWh, heat usually will be worth 1.3-1.5 times the cost of the fuel, and electricity usually will be worth 2-3 times the cost of the fuel, all per-unit energy.

A simple example illustrates calculation of the hourly cogeneration earnings (CE). A 100-kW cogeneration module is either operating at full capacity or it is off. The electricity produced is worth 6¢/kWh and the heat produced (600×10^3 Btu/h) is worth \$6/10^6 Btu so the energy produced is worth \$9.60/h (100 kW x 6¢/kWh + 0.6×10^6 Btu/h x \$6/10^6 Btu). This module has a maintenance cost of 2¢/kWh and burns fuel worth \$4/10^6 Btu at a rate 1.3×10^6 Btu/h, so the module costs \$7.20/h (100 kW x 2¢/kWh + 1.3×10^6 Btu/h x \$4/10^6 Btu) to operate. The value of CE is \$2.40/h (\$9.60/h - \$7.20/h).

The second factor affecting payback period is how much the module is operated. The number of hours the module is operated annually (AH, h/year) multiplied by the value of CE gives the annual net energy earnings. If the module of the above example is operated 6000 h annually, then the annual net energy earnings (AH x CE) is \$14,400. (If a cogeneration system is operated at fractions of full load, then AH must be defined as the number of equivalent full load hours.)

The third factor affecting payback period is the value of avoided electric utility capacity charges (CC, \$/year). For instance, if the local electric utility charges the base \$6.00/kW of peak demand per month and if the 100 kW module of the example above were operated to reduce the base's peak electric demand by 100 kW, then the module would be earning \$600/month, that is avoiding CC of \$7200/year.

The final factor is the installed cost (IC, \$) of the module. With the installed cost and the above parameters, the simple payback period (SPP) can be written as:

$$SPP = \frac{IC}{AH \times CE + CC} . \qquad (5.1)$$

Equation 5.1 demonstrates that energy prices are not the whole story. Very favorable fuel prices that give a large CE can be defeated by a small AH. For example, an application which earns \$5/h of operation but is operated only 1000 h/year will be no more attractive than an application which earns only \$1/h of operation but is used 5000 h/year. A small AH can also lengthen the payback period by reducing the avoided capacity charges, (CC). For instance, it may be difficult to capture all the possible CC with a small AH. On the other hand, the CC may be captured by cogenerating when the recovered heat cannot be used or stored, but this might be a money-losing mode of operation.

Taking the UEPH at Pensacola as an example, AH is 8664 h (Table 5.1) and IC is \$58,000 (Table 5.2). Using these values in Eq. 5.1 gives an SPP of 5.6 years (as on Table 5.2). If the IC of the installed cogeneration module were to increase by 20%, then the SPP would increase by 20% to about 6.7 years. If the CE, were to increase by 20% (as it would if electricity prices were to increase by 6%) then the SPP would be reduced by 11% to about 5 years. If CE were to decrease by 20% (as it would if natural gas prices were to increase by 23% or if maintenance costs were 15% higher than estimated) then the SPP would be increased by 12% to 6.3 years. A 20% increase in peak electric demand charges (CC) would increase the CC by 20% and reduce the payback period by 8% to 5.1 years.

From this example, it is apparent that not only is the capital cost important but so are the maintenance costs. A 15% higher than expected maintenace would not be hard to imagine; so, a maintenance contract might protect the Navy from unanticipated costs. On the other hand, relatively small increases in electricity price can substantially improve the economic attractiveness, and larger fuel price increases reduce cogeneration attractiveness relatively little in this example. It should be noted that the insensitivity of cogeneration to fuel prices results from using the cogenerated heat fully. A cogeneration module which recovers a smaller part of the available heat or an application which makes less use of the cogenerated heat will be more sensitive to fuel prices.

5.4 Financing Options

The foregoing sections describe the economic attractiveness of decentralized small cogeneration. Several of these applications have SIRs of two or more, but all of the applications studied here take four or more years to pay off the original investment. Under these circumstances, capital moneys may not be readily available. One method for avoiding capital limitations is to enter into a third-party financing agreement. A wide variety of third-party financing arrangements are possible, but a careful examination of the options is desirable before entering into a third-party contract. Two types of such agreements are described below.

Third-party financing (TPF) is a technique which would allow the Navy to benefit from cogeneration without having to purchase and operate the equipment. Where capital funds are limited, TPF may allow the Navy to capture cogeneration benefits which would otherwise be unavailable. However, TPF has disadvantages, the principal one being is that the cogeneration earnings must be shared with the investors. Another disadvantage is that a third-party finance contract somewhat restricts the Navy's choice in energy conservation activities in the buildings equipped with cogeneration. For example, if the cogenerated heat is used principally to provide domestic hot water to a barrack, then a low-cost energy conservation technique like installing low-flow shower heads could be prohibited by the agreement.

5.4.1 Fixed-Fee Financing

The first technique is called fixed-fee financing. In this approach, the investors enter into a contract with the Navy under which they purchase, install, and operate the cogeneration device for a fixed annual or quarterly fee for a period of about ten years. The Navy would provide fuel, use the heat and electricity produced, and pay the fee. The fee covers the costs of purchase, installation, financing, operation and maintenance, and profit.

The actual fee would, of course, be negotiated with the investors, but it can be estimated for the purposes of this study. The annual fee consists of an amount for maintenance, an amount for financing the module, and an additional 20% to cover profit and contingencies. The annual amount for financing can be estimated by assuming that the installed cost of the module is amortized over the life of the contract (about 10 years) at an interest rate 1% above the 10-year treasury note interest rate.

This technique has the advantage that all the cogeneration savings go to the Navy. Also, the costs of operation (excluding fuel) and maintenance fall on the investors. On the other hand, there are disadvantages. The contract must include an incentive for efficient operation. The incentive may make the otherwise simple contract rather complicated in practice. The Navy bears most of the risk on future energy prices; the contract requires the Navy to make annual payments even if energy prices become such that it is less expensive not to run the cogeneration equipment.

5.4.2 Shared Savings

This third-party finance technique does not require the Navy to make any fixed payment. Instead the dollar savings resulting from use of cogeneration is shared with the investors according to a mutually agreed upon formula. Since the investors bear a substantial part of the risk, they require 50-90% of the savings and a five-year or longer contract. In the event that future energy prices make cogeneration unattractive to both the Navy and the investors, the contract could be terminated by mutual agreement.

The fractions of the savings going to the Navy and to the investors depend in large measure on the investors' assessment of the riskiness of the investment. Where the expected payback period is short, the investors will be willing to settle for a smaller fraction of the savings. Investors generally require a 15-20% after-tax return on investment. Tax laws play an important part in the attractiveness of third-party finance. In this case, the availability of investment tax credits and rapid depreciation of investment for tax purposes yield higher after-tax returns-on-investment and, consequently, a larger share of the savings for the Navy.

The principal disadvantage of this type of TPF is that the Navy receives considerably less than the full savings. Balancing out this disadvantage are several advantages. The Navy has to make no capital outlay for the cogeneration equipment or installation. Further, the investors, not the Navy, bear the biggest part of the risk. Since the Navy has put up none of the money, the principal risk to the Navy is that some more attractive energy-conserving opportunity will be foreclosed by the contract with the investors. Another advantage of shared savings is that the investors have a built-in incentive to operate the cogeneration equipment efficiently.

6. SUMMARY AND CONCLUSIONS

This assessment has four principal parts: (1) a review of available small cogeneration equipment, (2) an in-depth data collection effort on three common types of Navy buildings at four Navy bases, (3) a rough design wherein cogeneration systems were matched to individual buildings, and (4) an estimation of the economic attractiveness of the small cogeneration applications. Each part reveals different aspects of small cogeneration applications on Navy bases.

Small cogeneration modules can be cast into two groups: the larger, heavy-duty equipment marketed by Martin and Cogenics and the smaller, less-expensive equipment produced by Thermo Electron and WESI. Installed costs are in the range of $700 to $1000 per kilowatt of electric generating capacity (except for the smallest modules which are close to $2000/kW). The modules are far from uniform in efficiency and features. Considerable care is advisable in selecting a cogeneration module to avoid purchasing more or less than needed. Some of these modules exist as designs only; the ones that have been built have not been in operation long enough to have a reliability record.

Hospitals, UEPHs, and UOPHs were studied at each of four Navy bases. Domestic hot water was identified as the best small cogeneration heating load since it is nearly constant throughout the year. Very few data on DHW energy consumption were available in any of the buildings. A small amount of hourly DHW data from a UEPH on a fifth Navy base was used to estimate DHW energy consumption for UEPHs and UOPHs and to size heat storage for use in these applications. Hot water use in hospitals was <u>assumed</u> to be half the minimum monthly heat consumption. The extreme paucity of data on hot water energy consumption in buildings is one cause of uncertainty of this assessment.

Reasonably close matches between DHW load and module output were possible because of the wide variety of module sizes offered by WESI; especially below 60 kW. The UOPHs examined are almost too small to be served by a cogeneration module. Because of the unavailability of natural gas, a relatively large diesel-fueled module was used for the UEPH at Groton. The excessively large module is partly responsible for the poor economic performance of this application. All the cogeneration applications include heat storage because it was recognized that either the use or the overall efficiency of the cogeneration module would be reduced if TES were not included.

The small cogeneration applications which have the most attractive economic characteristics are those where an efficient and moderately priced module was available in the appropriate size and where fuel and electricity prices are conducive to cogeneration. All the applications at Millington are unattractive because the electricity price is too low (2.574¢/kWh). The UOPH application at Pensacola is unattractive because the appropriately sized cogeneration module (VRG 155/15) is too expensive and not sufficiently efficient. The UEPH and hospital applications at Pensacola are large enough to use reasonably-priced efficient cogeneration modules, and Pensacola has high enough electricity prices (3.64¢/kWh). At Point Mugu, the fuel and electricity prices are exceptionally good for cogeneration. Electricity prices are high and natural gas costs about $2 per million Btu less if it is used for cogeneration than if it is used for other purposes.

Several specific conclusions emerge from this assessment:

(1) Attractive applications are likely to be found at buildings that have an average minimum heat load which is large enough to allow the use of an efficient and reasonably-priced (approximately $700/kW, installed) cogeneration module; on the basis of the available cogeneration modules, this requires an average minimum heat load of about 200,000 Btu/h.

(2) Attractive applications were found where energy prices are as low as 3.5¢/kWh for electricity and $3.50 per million Btu for natural gas.

(3) One of the keys to attractive applications is high utilization of the cogeneration equipment; this calls for installation of less, rather than more, cogeneration capacity than can be used.

(4) In applications with uneven energy use, such as barracks, thermal energy storage is essential.

(5) If nonpressurized storage tanks are used for domestic hot water thermal energy storage, then thermal energy storage should cost about $2 per thousand Btu.

(6) In no case examined here was it economically attractive to operate the cogeneration module without recovering the cogenerated heat. Further, those modules which recover a larger fraction of the cogenerated heat will save more energy and money than those which recover a smaller fraction of cogenerated heat.

(7) In this limited study of eight buildings on four Navy shore facilities, three applications with simple payback periods of less than six years and four applications with SIRs greater than 1.0 were identified.

The principal uncertainties of this assessment are in the efficiencies, reliabilities, and installed costs of the small cogeneration modules. None of these cogeneration modules have been widely used. All the specifications given here are those reported by the manufacturers. In many cases, test data on modules are not available. In most cases, field performance of modules has not been verified. The use of 1800-rpm engines in many of these cogeneration modules is further reason for uncertainty, since the reliability of 1800-rpm engines in this type of application is not widely accepted.

Another uncertainty of this assessment is the timing and magnitude of hot water energy use in buildings. A considerable amount of effort was expended to estimate hot water energy use, but the data are poor and, consequently, the estimates are uncertian. Significant errors in the hot water energy use estimates will not affect the principal results of this study. However, the buildings which can use small cogeneration and the sizes of the cogeneration modules which would be used will be affected if the hot water energy use estimates are very far off. Before cogeneration modules are installed in a particular building better information on hot water energy use is needed.

In summary, the conditions required for attractive applications of decentralized small cogeneration are fairly common on Navy shore facilities. For instance, the electricity prices at Pensacola are not especially high, but higher electricity prices will be found in many parts of the country. In addition, the average minimum heat load requirements are met by many Navy buildings and complexes. UEPHs with occupancies of 300 or more are much more common than UOPHs. Hospitals are found on many Navy bases, and other building types such as mess halls may have large enough average minimum heat loads to justify use of small decentralized cogeneration.

7. RECOMMENDATIONS

In light of the money and energy saving potential of decentralized small cogeneration, the Navy should take the following action to answer the remaining uncertainties and to facilitate the use of small cogeneration:

(1) Perform several demonstrations of small cogeneration where the economics are attractive to build a body of experience on the installation and maintenance costs and on the efficiency and reliability of these cogeneration modules.

(2) Monitor hot water energy consumption in a few hospitals and UEPHs (perhaps in concert with demonstrations) to learn the minimum heat load and the times of its use through the course of a typical day or week. This knowledge will permit proper sizing of cogeneration modules and thermal energy storage stystems for hospitals and UEPHs.

(3) In light of the attractiveness of decentralized small cogeneration for UEPHs and hospitals, examine other building types on Navy shore facilities, such as food facilities, commissaries, and large administration buildings for potential application of small cogeneration.

(4) Assess the market for and significance of the small cogeneration on Navy shore facilities. The results of such a market survey could help the Navy by showing which decentralized small cogeneration application types are of most importance to the Navy. Further, it would help determine which cogeneration modules will be of most use and guide the allocation of Navy research and development efforts.

(5) Develop guidelines for evaluating potential decentralized small cogeneration applications by Navy personnel which would facilitate the use of small cogeneration.

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APPENDIX A

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C   THIS IS A PROGRAM TO EXPLORE THE EFFECTS OF THERMAL ENERGY
C   STORAGE SIZE ON DECENTRALIZED SMALL COGENERATION USED TO MEET
C   A DHW LOAD.
C
      DIMENSION CON(80), STOHT(80)
C
      DATA COGHT,STOCAP,RUNHRS,BACKUP/111.7375,1117.375,0.,0./
C
      DATA CON/0.,0.,0.,0.,0.,0.,0.,353.,
     C 0.,121.,684.,
     C 0.,0.,0.,0.,0.,96.,550.,
     C 0.,0.,0.,0.,0.,28.,873.,
     C 0.,0.,282.,489.,
     C 0.,0.,0.,0.,462.,317.,
     C 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,270.,369.,
     C 0.,0.,0.,755.,0.,0.,0.,0.,457.,206.,
     C 0.,0.,0.,543.,158.,0.,0.,0.,0.,0.,0.,68.,960.,
     C 0.,0.,0.,0.,0.,0.,0.,0.,898.,0./
C
      DO 333 K = 1,11
        STOCAP = 1229.1125 - 111.7375*K
C
      DO 222 J = 1,16
        COGHT =44.695 + 11.17375*J
C
      STOHT(1) = COGHT - CON(1)
      RUNHRS = 1.0
      BACKUP = 0.0
      DO 111 I = 2,80
        IM1 = I - 1
        STOHT(I) = STOHT(IM1) + COGHT - CON(I)
        IF(STOCAP .LE. STOHT(I)) GO TO 7
        RUNHRS = RUNHRS + 1.
        GO TO 10
  7    STOHT(I) = STOCAP
       RUNHRS = RUNHRS + (STOCAP-STOHT(IM1)+CON(I))/COGHT
C
 10   CONTINUE
C
      IF(STOHT(I) .GE. 0.) GO TO 111
        BACKUP = BACKUP - STOHT(I)
        STOHT(I) = 0.
C
  111  CONTINUE
C
      COGR = STOCAP/COGHT
      CHTR = COGHT/111.7375
      CAPR = STOCAP/111.7375
      PROR = (8939. - BACKUP)/ 8939.
      HRATIO = RUNHRS / 80.
```

```
C
      WRITE(23,123) STOCAP,COGHT, RUNHRS, BACKUP, CAPR, CHTR, COGR,
     C PROR, HRATIO
 123  FORMAT(5F10.3)
C
      WRITE(23,234) (STOHT(I),I=1,80)
 234  FORMAT(1X,24F5.0)
C
 222  CONTINUE
 333  CONTINUE
      STOP
      END
```

END

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